US Army Corps
of Engineers
Construction Engineering
Research Laboratories

USACERL Technical Report FE-95/01
October 1994

Energy Supply Alternatives for the Year 2002 at the U.S. Military Academy (USMA)

by
Mike C.J. Lin, Mike Binder, and Richard G. Andersen

The U.S. Military Academy (USMA) is concerned about how to meet present and future energy demands as the existing generating equipment and distribution facilities age. To help the installation develop an energy supply plan, the USMA asked the U.S. Army Construction Engineering Research Laboratories to determine options for future energy supply, taking into consideration both the projected increases in energy demands and the Army's energy conservation goals. Researchers considered 68 separate plans based on plant location; type of distribution system; cogeneration; steam, hot water, and chilled water technologies; coal, gas, and fuel oils; and environmental constraints.

Based on this study, the lowest cost plan is to refurbish the existing power plant with new high pressure gas/oil boilers and new steam turbine generators. If the USMA decides to build a new plant, non-cogeneration using gas/oil-fired boilers or cogeneration using gas turbine generators with heat recovery boilers should be used. The existing steam distribution system should be maintained with repairs as needed. A new central chiller plant is not recommended.

The USMA should assess fuel costs, electrical energy costs, and capital costs for the top five economically ranked plans before proceeding with an energy construction project.

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REPORT DOCUMENTATION PAGE

Form Approved
OMB No. 0704-0188

1. AGENCY USE ONLY (Leave Blank)	2. REPORT DATE	3. REPORT TYPE AND DATES COVERED
	October 1994	Final

4. TITLE AND SUBTITLE
Energy Supply Alternatives for the Year 2002 at the U.S. Military Academy (USMA)

5. FUNDING NUMBERS
Project W39 and WC1, MAEN-88-89

6. AUTHOR(S)
Mike C.J. Lin, Mike Binder, and Richard G. Andersen

7. PERFORMING ORGANIZATION NAME(S) AND ADDRESS(ES)
U.S. Army Construction Engineering Research Laboratories (USACERL)
P.O. Box 9005
Champaign, IL 61826-9005

8. PERFORMING ORGANIZATION REPORT NUMBER
TR FE-95/01

9. SPONSORING/MONITORING AGENCY NAME(S) AND ADDRESS(ES)
United States Military Academy (USMA)
ATTN: MAEN-S
West Point, NY 10996-1592

10. SPONSORING/MONITORING AGENCY REPORT NUMBER

11. SUPPLEMENTARY NOTES

Copies are available from the National Technical Information Service, 5285 Port Royal Road, Springfield, VA 22161.

12a. DISTRIBUTION/AVAILABILITY STATEMENT
Approved for public release; distribution is unlimited.

12b. DISTRIBUTION CODE

13. ABSTRACT (Maximum 200 words)

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14. SUBJECT TERMS
energy research
energy conservation
economic analysis
energy supply alternatives
Life Cycle Cost in Design (LLCID)
U.S. Military Academy (USMA)

15. NUMBER OF PAGES
110

16. PRICE CODE

17. SECURITY CLASSIFICATION OF REPORT	18. SECURITY CLASSIFICATION OF THIS PAGE	19. SECURITY CLASSIFICATION OF ABSTRACT	20. LIMITATION OF ABSTRACT
Unclassified	Unclassified	Unclassified	SAR

FOREWORD

This research was performed for the United States Military Academy (USMA), West Point, NY under Project W39 and WC1, MAEN-88-89. The USMA technical monitor was Richard Heidmann, MAEN-S.

The research was performed by the Fuels and Power Systems Team (FEP) of the Energy and Utility Systems Division (FE), of the Infrastructure Laboratory (FL), of the U.S. Army Construction Engineering Research Laboratories (USACERL). The project's principal investigators were Mike C.J. Lin and Mike Binder. The primary contractor for this project was Stanley Consultants of Muscatine, IA; Richard G. Andersen was the Stanley Consultants principal investigator. Gary Schanche is Team Leader, CECER-FEP, Donald Fournier is Acting Division Chief, CECER-FE, and Dr. David M. Joncich is Laboratory Chief, CECER-FL. The USACERL technical editor was Gloria J. Wienke, Information Management Office.

LTC David J. Rehbein is Commander and Acting Director of USACERL. Dr. Michael J. O'Connor is Technical Director.

EXECUTIVE SUMMARY

The U.S. Military Academy (USMA) is concerned about how to meet present and future energy demands as the existing thermal and electric generating equipment as well as the energy distribution facilities approach the end of their service lives. To help the installation develop an energy supply plan, the USMA asked the U.S. Army Construction Engineering Research Laboratories (USACERL) to determine options for future energy supply that account for both the projected increases in demand and the Department of the Army's energy conservation goals. Included in the options considered was an investigation of the ability of the existing facilities to meet increasing energy demand as well as their condition and estimated remaining life. Alternatives considered in this study include plant locations, distribution systems, cogeneration, steam, hot water and chilled water technologies, coal, gas and oil fuels, environmental constraints, emerging technologies, and other conventional technologies.

Results of the intense data gathering efforts and inspection of existing facilities conducted at USMA January 16 through 19, 1990, analysis of the data collected and facilities inspected, and a prioritized list of recommended maintenance for the existing facilities are included in "Appendix A, Interim Report on Existing Thermal and Electric Systems Analysis" of an unpublished report, *Premilinary Report on Energy Supply Alternatives for the Year 2002 at USMA* by Stanley Consultants (November 1990).

The prioritized recommended maintenance consists of the following items:

- Evaluate boiler water chemical treatment with the chemical supplier/consultant and adjust chemical feed in accordance with the evaluation.

- Repair or replace deaerator in power plant.

- Test additional condensate samples for impurities as recommended for about a week. Track down sources of hardness in condensate returns (believed to be leaking heat exchangers in buildings) and repair them. If hardness in condensate returns cannot be corrected, consider adding a condensate polisher.

- Test treated water makeup for hardness as recommended for about a week. If hardness is present, determine the cause and correct it as recommended.

- Repair or replace inoperable condensate pumping units.

- Repair or replace any leaking condensate return piping.

- Repair or replace any leaking direct burial steam distribution conduits.

Researchers considered 68 separate plans, including various options. An economic screening analysis was conducted for 44 of these plans. The top 12 plans from the screening analysis (see listing on next page) were further evaluated on a life cycle cost basis using the Life Cycle Cost in Design (LCCID) economic analysis computer program. The LCCID program was developed by USACERL in conjunction with the U.S. Army Corps of Engineers, Missouri River Division (Lawrie 1988).

Eleven of the plans involving emerging technologies or other conventional technologies were not evaluated in economic terms because of known technical or economic inadequacies and are not recommended for the USMA at this time.

The top 12 alternative plans are as follows, ranked from the lowest life cycle cost to the highest life cycle cost as determined by the LCCID analysis.

Plan No.	Plan Name	Present Day Capital Costs ($x10^3$ dollars)	Present Value of Total Life Cycle Costs ($x10^3$ dollars)
1A	Refurbish Existing Steam Heat and Cogeneration Plant - New Gas/Oil-Fired Boilers and Steam Turbine Generators - Retain Existing Chillers, Add Absorption Chillers for New Buildings	19,959	44,402
3A	New Gas/Oil-Fired Central Steam Plant - Retain Existing Chillers, Add Centrifugal Chillers for New Buildings	29,286	49,561
1E	Refurbish Existing Steam Heat and Cogeneration Plant - New Gas/Oil-Fired Boilers and Steam Turbine Generators - Replace Existing Centrifugal Chillers with Absorption, Add Absorption Chillers for New Buildings	31,154	51,012
3D	New Gas/Oil-Fired Central Steam Plant - Replace Existing Absorption Chillers with Centrifugal, Add Centrifugal Chillers for New Buildings	36,350	51,103
11A	New Cogeneration-Simple Cycle Gas Turbine, Retain Existing Chillers, Add Absorption Chillers for New Buildings	41,995	51,352
13A	New Cogeneration-Diesel Engines, Gas/Oil-Fired, Retain Existing Chillers, Add Absorption Chillers for New Buildings	43,958	51,748
12A	New Cogeneration-Combined Cycle Gas Turbine Retain Existing Chillers, Add Absorption Chillers for New Buildings	42,447	52,896
2A	Refurbish Existing Steam Heat and Cogeneration Plant - New Coal/Water-Fired Boilers and Steam Turbine Generators - Retain Existing Chillers, Add Absorption Chillers for New Buildings	51,128	55,227
5A	Hot Water Heat - New Central Gas/oil-Fired Plant, Convert Existing Absorption Chillers to Hot Water, Add Centrifugal Chillers for New Buildings	44,818	56,673
11E	New Cogeneration-Simple Cycle Gas Turbine, Replace Existing Centrifugal Chillers with Absorption, Add Absorption Chillers for New Buildings	53,190	57,859
3C	New Gas/Oil-Fired Central Steam Plant - New Central Centrifugal Chiller Plant	53,422	57,992
13E	New Cogeneration-Diesel Engines, Gas/Oil-Fired, Replace Existing Centrifugal Chillers with Absorption, Add Absorption Chillers for New Buildings	55,153	58,305

Steam load assessment at USMA indicates a moderate increase in peak boiler load from 185,000* lb/h in 1990 to 196,000 lb/h by the year 2000 (from 210,000 lb/h to 221,000 lb/h including the laundry boiler plant). Chilled water cooling capacity is predicted to increase from the current 4,135 tons to 5,335 tons. Peak electric load will likely increase from 14,130 kW to 15,780 kW by 2000.

These energy loads can be served by non-cogenerating facilities (all electric energy purchased from Orange and Rockland) or by cogenerating facilities (a portion of the electric energy is generated and the remainder is purchased from Orange and Rockland). The proposed cogeneration plans would generate approximately one-half of the annual electrical loads and all of the annual thermal loads. It is not economically feasible to cogenerate all the electrical needs of the Academy. Both non-cogenerating and cogenerating facilities were analyzed.

All environmental regulations for fuel burning technologies considered can be met with conventional and emerging pollution control technologies, which are included with each plan studied. New regulations recently issued will likely eliminate use of No. 5 fuel oil due to its sulfur content and No. 2 fuel oil will be used as the standby fuel. Natural gas would be the primary fuel for most plans. Acquisition of the various permits required to implement any of the coal firing plans will likely be difficult due to local public opposition. Solid waste generated by coal firing should be disposed of by return hauling to the coal mine. Noise, transportation, and thermal impacts would not be significant for any plan located at any of the sites considered. However, oil or coal would need to be trucked in for any of the new sites considered.

Four sites were considered for new plants. Site 1 located near Washington Gate presents the lowest cost of the four sites and will be in a designated industrial area. Sites 2 and 3 are only slightly higher in cost than Site 1, but present other disadvantages in being much closer to the cadet area and the Stoney Lonesome area. Requirements for adequate power plant stack height to promote effluent dispersion (good engineering practice) will likely allow stacks to be visible from the cadet area for Sites 1 and 3. Estimated stack height would be about 200 feet for coal-fired central plants. All other alternatives would likely require stack heights of about 100 feet. Sites 2 and 4 should not allow stacks to be visible from the cadet area. Site 4 (remote from the Academy on Highway 283) will have a large economic impact on any plan considered ($23,000,000 added cost due to increased length of distribution systems) and will impose plant operating efficiency penalties. Site 1 is recommended for all plans that include a new power plant.

Replacement of the existing steam distribution system was compared to reuse of the existing system. A new system will add approximately $25 million to the cost of any plan considered with little payback on investment other than reduced maintenance costs for the first 10 years of operation. Reuse of the existing steam distribution system is recommended along with a diligent inspection, repair, and replacement program on an as needed basis. Because the existing direct burial steam and condensate conduits are experiencing leakage, repairs or replacement cannot wait 10 years until a power plant project is implemented.

Five chilled water options were considered as follows:

- Use the existing chillers in the buildings as is,
- Replace all chillers with a new central centrifugal chiller plant for non-cogeneration plans,
- Replace all chillers with a new central absorption chiller plant for cogeneration plans,
- Replace absorption chillers in buildings with centrifugal chillers for non-cogeneration plans, and
- Replace centrifugal and reciprocating chillers in buildings with absorption chillers for cogeneration plans.

* The peak boiler load of 185,000 lb/hr in 1990 is high based on latest information received from USMA on 15 March 1991. Refer to discussion of future steam loads in Chapter 2.

In all cases, the most economic option was to use the existing chillers "as is" due to the high capital cost of replacement facilities. Thermal storage was also considered but is not economically feasible due to the structure of Orange and Rockland electric rates and investment costs of storage facilities.

None of the coal-fired plans (either cogeneration or non-cogeneration) are very attractive in economic terms. This is due to the high capital costs and high costs for coal and solid waste disposal associated with these plans. This is typical for small power plants of this type that are not located close to coal mines. Use of a coal/water mixture with new boilers in the existing power plant (Plan 2A) is the lowest cost coal-fired plan, but the equipment required will create a very crowded boiler room.

The highest cost plans were Plan 16D, an all electric plan and Plans 14A and 15A, third-party financed cogeneration plans that should not be considered due to their high life cycle costs.

Plan 1A, refurbish the existing power plant with new gas/oil-fired boilers and new steam turbine generators, is the lowest cost plan and is recommended as the best plan for USMA at this time. If a new plant must be built on a new site as recommended by the Hillier Group in the Master Plan Report (Hillier Group 1989) then Plan 3A, a non-cogenerating plant with gas/oil-fired boilers, or Plan 11A, a simple cycle gas turbine plant with waste heat recovery boilers, should be constructed at Site 1.

Fuel costs are changing rapidly and should be carefully monitored since a large swing in fuel costs could affect the ranking of some plans relative to other plans. Fuel costs and capital costs should be reevaluated for the top five plans before proceeding with a power plant construction project scheduled for the years 2000 to 2002.

CONTENTS

CONTENTS (Cont'd)

TABLES

FIGURES

FIGURES (Cont'd)

ENERGY SUPPLY ALTERNATIVES FOR THE YEAR 2002 AT THE U.S. MILITARY ACADEMY

1 INTRODUCTION

Background

The U.S. Military Academy (USMA), West Point, New York, is concerned about how to meet present and future energy demands as the existing thermal and electric generating equipment and the energy distribution facilities for the installation approach the end of their service lives. To help the installation develop an energy supply plan, the USMA asked the U.S. Army Construction Engineering Research Laboratories (USACERL) to determine options for future energy supply, taking into consideration both the projected increases in energy demands and the Department of the Army's energy conservation goals.

Objectives

The overall objectives of this study were to evaluate the existing thermal and electrical production facilities at the USMA; identify and evaluate technologies and opportunities to improve the efficiency of energy production; and develop alternative energy supply systems for the year 2002.

Approach

Researchers gathered historical and current operation and maintenance data on the energy production and distribution facilities to determine their ability to meet increasing demand. Various alternatives were studied to determine the most cost effective method of meeting growth and conservation goals. The alternatives examined included new plant locations, distribution systems, cogeneration and steam, hot water and chilled water generation technologies, as well as emerging technologies that generally conform to the "Master Plan Report-Plan for the Year 2002, United States Military Academy" (Hillier Group 1989).

The specific tasks undertaken to support the study objectives are summarized below.

1. Collect available information on historical and current operation and maintenance of existing facilities.

2. Perform a visual inspection of each major power system in the existing thermal and electrical generation and distribution facilities to determine condition, approximate operating efficiency, and ability to meet future energy needs.

3. Evaluate the potential for upgrading existing power system equipment based on the information collected. The evaluations included an economic analysis of each major system with an estimate of the expected life of renovated equipment and an evaluation of the reliability of performance (a trip to the site

to gather data and analyze the existing facilities was conducted 16 to 19 January 1990). An interim report on the condition of the existing facilities was completed 10 April 1990.*

4. Develop approximately 35 alternative energy supply systems for the installation. The primary power and thermal supply network must meet both utility and zoning needs. The following general types of approaches were considered in developing alternative energy supply systems: (1) conventional approach with constrained budget, reasonable capital improvements, and payback, (2) exotic (fuel/system) approach using unproven methods or arrangements still under development, (3) innovative engineering approach using generally known and used systems with ideal locations and distribution methods, unconstrained capital budget.

5. Perform a screening analysis of the alternatives to identify technologies with the most economic benefit to the installation. This analysis included required boiler and chiller reserve capacity, allowable loads for electrical and thermal distribution systems, and contingency plans. Environmental constraints were identified. The screening analysis included an economic analysis of all alternative energy supply systems developed (except Plans 17 through 27, which were judged to be either technically or economically unacceptable for the USMA). Economic analysis of life cycle costs was prepared using the Life Cycle Cost in Design (LCCID) computer program for the 12 top-ranked plans. Cost projections were compared and the alternative plans ranked according to the present value of their life cycle costs.

Study Assumptions

This energy supply screening study includes the following assumptions:

- All facilities, with the exception of a new power plant, recommended in the "Master Plan Report-Plan for the Year 2002, United States Military Academy" prepared by the Hillier Group, will be installed in accordance with the Master Plan Report.
- Projected steam and electrical loads were calculated based on current use plus additional loads for new buildings and building additions scheduled in the "Master Plan Report."
- Sufficient quantities of natural gas will be available for any alternative plan using this fuel.
- The use of No. 5 fuel oil will be discontinued at the USMA due to sulfur emission limits for new facilities. Gas or coal will become the primary fuel.
- Sufficient quantities of No. 2 fuel oil will be available to satisfy any alternative plan as a standby fuel.
- For any alternative plan using coal fuel, all coal combustion wastes such as fly ash, bottom ash, and scrubber wastes will be returned to the coal mine for disposal.
- Total steam generation includes 15 percent for feedwater heating and miscellaneous power plant use.
- Any new power plant will be located at an elevation of 400 ft.**
- Average makeup water temperature before treatment is 60 °F. The deaerating heaters provide 227 °F feedwater to the steam boilers.
- All new gas or oil fuel burning facilities will be limited to 10 parts per million by volume, dry (ppmvd) NO_x emissions.

* Full details are included in "Appendix A, Interim Report on Existing Thermal and Electric Systems Analysis," to Unpublished Report *Preliminary Report on Energy Supply Alternatives for the Year 2002 at USMA* (Stanley Consultants, November 1990). Appendix A presents results of the data gathering efforts and inspection of existing facilities conducted at USMA January 16-19, 1990, results of the analysis of the data collected and facilities inspected, and a prioritized list of recommended maintenance for the existing facilities as required by the project scope.

** A metric conversion table is on page 106.

- Yearly maintenance costs are 2.5 percent of capital cost for all power plant plans and 1 percent of capital cost for chiller facilities.
- Cost of makeup water for all plans will be $4.00 per 1000 gal in 1990 dollars.
- Boiler blowdown is neglected as is additional steam generated by desuperheaters. These should approximately offset each other.
- Steam generated in a solid waste incinerator plant is not included in total steam generation for any of the alternative plans. Steam available would be less than 3000 pounds per hour (lb/hr) (Griggs, May 1994).

2 ENERGY LOADS AND SUPPLY SYSTEMS

Existing Facilities, Fuels, and Steam Loads

The Central Power Plant (CPP), Building No. 604, is located near the west bank of the Hudson River. It provides steam to the buildings in the eastern portion of the Academy in the area separated from the south and west by Wilson Road, Eichelberger Road, Howze Place, Mills Road, Washington Road, and Ardee Place to the northwest. The Hudson River forms the eastern and northern boundary of the plant's service area.

The Laundry Plant, near the Washington Gate area, provides steam to several other buildings in its vicinity. Many buildings throughout the installation have individual heating systems.

Existing Facilities

Superheated steam is generated at 160 pounds per square inch gauge (psig) and 425 °F by two boilers in the CPP. A third boiler is in poor condition and is not approved for operation. Nameplate boiler capacities are:

Boiler No. 1 - 200,000 lb/h
Boiler No. 2 - 200,000 lb/h
Boiler No. 3 - 180,000 lb/h (not operating)

Boilers 1 and 2 were manufactured by Keeler and installed in 1968. Boiler 3, which was installed in 1938, was scheduled to be replaced by a new 80,000 lb/h unit in 1992.

The CPP contains three steam turbine/electric generators. Pertinent data for these turbine/generators follows:

Turbine/ Generator Number	Manufacturer	Capacity, kW	Inlet Steam Condition psig/°F	Exhaust psig	Year Installed
1	Murray	1,250	160/420	12	1978
2	Murray	1,250	160/420	12	1978
3	Murray	1,750	160/420	12	1975

The CPP includes the following auxiliary equipment:

- Air heaters with steam coil preheat,
- Dual drive (electric motor and steam turbine) forced draft fans,
- No. 5 fuel oil burners and burner management system,
- Boiler controls, electric/pneumatic,
- Deaerating heater, 400,000 lb/h capacity,
- Two steam heated and one electrically heated fuel oil pump/heater sets,
- Two steam turbine and one motor driven boiler feed pumps plus two motor driven summertime feed pumps,
- Instrument and service air compressors,

- Three 700,000-gal No. 5 fuel oil storage tanks with suction heaters, and two 30,000-gal day tanks, and
- Cold zeolite water softeners and boiler water treatment system.

The Laundry Plant, Building No. 845, includes two Bigelow field-erected boilers, each with a capacity of 40,000 lb/h steam. Design steam pressure is 140 psig but these boilers are normally operated at 100 psig, saturated.

Fuels

The primary fuel for the CPP boilers is No. 5 fuel oil, although No. 6 fuel oil can be fired. Natural gas and No. 5 fuel oil are used for the Laundry Plant boilers and individual building heating boilers. Natural gas, if available, is always used to fuel the Laundry Plant boilers. Standby fuel is No. 5 oil.

No. 5 fuel oil characteristics are:

Sulfur Content - 1.0 percent
Nitrogen Content -1.35 percent
Heating Value - 148,000 British thermal units per gallon (Btu/gal)

Coal bunkers and all coal and ash handling equipment have been removed from the CPP building.

Steam Loads

Current steam loads were derived from a Pope, Evans, and Robbins (P.E.R.)unpublished report "Volume III - Energy Balance Study," prepared in May 1972. That study presented design steam loads for summer and winter, for both turbine exhaust and high pressure steam supplies. Since the values are "design steam loads," it was necessary to adjust them to agree with actual historic peak steam loads of 185,000 lb/h (Hillier Group 1989). This was accomplished as follows:

- The building list entitled "Design Steam Loads-Central Steam Distribution System" from the P.E.R. Study was compared to the current building inventory at the USMA. Buildings that no longer exist were removed from the list and newly constructed buildings were added. The heat loads assigned to the newer buildings are based on heat loads of similar existing buildings.
- A heat transfer coefficient was computed using the following formula:

$$\text{Heat Transfer Coefficient} = \frac{T_2 - T_1}{\text{Building Heat Load}} \qquad \text{[Eq 1]}$$

where: T_2 = design indoor winter air temperature: 68 °F
T_1 = design outside winter air temperature: 4 °F and
Building Heat Load was obtained from the P.E.R. Study.

From the heat transfer coefficient, monthly steam consumption was calculated on a normalized heating degree day calculation (65 °F base). From the steam consumption, monthly fuel consumption was calculated. The heat transfer coefficient was adjusted so the calculated fuel consumption was approximately equal to the actual fuel consumption during 1989.

Results of this analysis are shown in Table 1, by month for each building that uses steam.

Table 1

Existing Monthly Steam Consumption

USMA ENERGY STUDY
PREDICTED MONTHLY STEAM CONSUMPTION FOR HEATING, ABSORPTION COOLING AND DOMESTIC HOT WATER - EXISTING
BASED ON NORMALIZED HEATING DEGREE DAYS, BASE 65 F

Bldg. No.	Building	Adjusted Heat Transfer Coefficient (MBtu/Hr-F)	JAN #'s Steam	FEB #'s Steam	MARCH #'s Steam	APRIL #'s Steam	MAY #'s Steam	JUNE #'s Steam	JULY #'s Steam	AUG #'s Steam	SEPT #'s Steam	OCT #'s Steam	NOV #'s Steam	DEC #'s Steam
1-4	Central Apartments	35.80	424179	365379	308151	170741	79553	12263	2830	6918	42449	132694	239603	381101
25-27	Central Apartments	15.86	187928	161877	136523	75645	35245	5433	1254	3065	18807	58788	106153	168842
28	Central Apartments	4.53	53694	46251	39006	21613	10070	1552	358	876	5373	16797	30330	48241
29	Central Apartments	4.53	53694	46251	39006	21613	10070	1552	358	876	5373	16797	30330	48241
30	Central Apartments	4.53	53694	46251	39006	21613	10070	1552	358	876	5373	16797	30330	48241
31	Central Apartments	4.53	53694	46251	39006	21613	10070	1552	358	876	5373	16797	30330	48241
32-33	Central Apartments	14.73	174504	150314	126771	70241	32728	5045	1164	2846	17463	54589	98571	156782
34-35	Central Apartments	14.73	174504	150314	126771	70241	32728	5045	1164	2846	17463	54589	98571	156782
40-41	Central Apartments	18.35	217459	187315	157976	87532	40784	6287	1451	3546	21762	68026	122834	195375
42-44	Central Apartments	14.16	167792	144533	121895	67540	31469	4851	1119	2736	16792	52490	94780	150752
45-47	Central Apartments	14.16	167792	144533	121895	67540	31469	4851	1119	2736	16792	52490	94780	150752
48-50	Central Apartments	15.86	187928	161877	136523	75645	35245	5433	1254	3065	18807	58788	106153	168842
100	Supt. Quarters	12.01	142288	122564	103367	57274	26686	4114	949	2320	14239	44511	80373	127838
101	Command of Cadets	4.98	59063	50876	42907	23774	11077	1708	394	963	5911	18476	33362	53065
102	Professors' Quarters	7.25	85910	74001	62410	34580	16112	2484	573	1401	8597	26875	48527	77185
103&104	Professors' Quarters	14.50	171819	148002	124821	69161	32224	4967	1146	2802	17195	53749	97054	154370
105&106	Officers' Quarters	7.25	85910	74001	62410	34580	16112	2484	573	1401	8597	26875	48527	77185
107&108	Officers' Quarters	12.46	147657	127189	107268	59435	27693	4269	985	2408	14777	46191	83406	132662
109	Officers' Quarters	11.33	134234	115626	97516	54032	25175	3881	896	2189	13433	41992	75824	120602
144	Quarters	2.38	28189	24282	20478	11347	5287	815	188	460	2821	8818	15923	25326
149	Lincoln Hall	38.52	456395	393129	331555	183708	85595	13195	3045	7443	45673	142772	257801	410045
600	Headquarters Bldg	52.11	617476	531881	448574	248547	115805	17851	4120	10070	61793	193162	348789	554767
601	Thayer Hall	253.75	3006840	2590028	2184361	1210314	563922	86929	20060	49037	300907	940613	1698452	2701475
602	Grant Hall/Grant Bks	86.09	1020178	878760	741123	410642	191331	29494	6806	16637	102093	319136	576261	916572
603	Officers' Club	32.85	389278	335316	282797	156692	73008	11254	2597	6348	38957	121776	219889	349745
604	Power Plant	0.00	0	0	0	0	0	0	0	0	0	0	0	0
605	Cullum Hall	34.44	408071	351504	296449	164257	76532	11797	2722	6655	40837	127655	230504	366629
606	Admissions/SJA/Health Clin	219.77	2604138	2243149	1891813	1048219	488397	75286	17374	42469	260607	814638	1470981	2339671
609	Mechanics Lab	4.42	52351	45094	38031	21072	9818	1513	349	854	5239	16377	29571	47035
618	Artillery Shed	9.97	118126	101751	85814	47548	22154	3415	788	1926	11821	36953	66725	106129
620	Barracks	44.18	523512	450942	380313	210724	98183	15135	3493	8538	52390	163767	295713	470346
622	Bowling Alley	30.59	362432	312191	263294	145886	67973	10478	2418	5911	36270	113377	204724	325624
624	Barracks	41.91	496666	427817	360810	199918	93148	14359	3314	8100	49703	155369	280548	446226
626	Housing/Transportation	28.32	335585	289066	243790	135080	62938	9702	2239	5473	33583	104979	189559	301504
627	Storage	16.99	201351	173439	146274	81048	37763	5821	1343	3284	20150	62987	113736	180902
632	Finance Signal, CPO	29.45	349008	300628	253542	140483	65455	10090	2328	5692	34927	109178	197142	313564
634	Post Office	3.96	46982	40469	34131	18911	8811	1358	313	766	4702	14697	26538	42211
635	Cadet Club	6.34	75171	64751	54609	30258	14098	2173	502	1226	7523	23515	42461	67537
637	Barracks	1.36	16108	13875	11702	6484	3021	466	107	263	1612	5039	9099	14472
639	Dir of Intercollegiate Ath	24.92	295315	254378	214535	118870	55385	8538	1970	4816	29553	92382	166812	265323
646	Printing Plant	6.12	72486	62438	52659	29177	13595	2096	484	1182	7254	22675	40945	65125
648	Multi Craft Shop	7.48	88594	76313	64361	35661	16616	2561	591	1445	8866	27714	50044	79597
655	Eisenhower Hall	453.13	5369357	4625051	3900645	2161276	1007003	155230	35822	87566	537334	1679666	3032951	4824063
663	Field House	65.70	778557	670632	565594	313385	146015	22508	5194	12697	77913	243551	439778	699489
665	Rifle & Pistol Range	24.47	289945	249753	210635	116709	54378	8382	1934	4729	29016	90702	163779	260499
667	Dir of Eng and Housing	135.94	1610807	1387515	1170194	648383	302101	46569	10747	26270	161200	503900	909885	1447219
671A	Thrift Shop	2.04	24162	20813	17553	9726	4532	699	161	394	2418	7558	13648	21708
671B	Thrift Shop	2.04	24162	20813	17553	9726	4532	699	161	394	2418	7558	13648	21708
673	Child Development Center	13.37	158396	136439	115069	63758	29707	4579	1057	2583	15851	49550	89472	142310
674	Hotel Thayer	189.18	2241707	1930959	1628519	902333	420424	64808	14956	36559	224337	701260	1266257	2014046
681	Provost Marshal	28.55	338270	291378	245741	136160	63441	9779	2257	5517	33852	105819	191076	303916
685	Band Barracks	45.31	536936	462505	390065	216128	100700	15523	3582	8757	53733	167967	303295	482406
687	Auxiliary Barracks	45.31	536936	462505	390065	216128	100700	15523	3582	8757	53733	167967	303295	482406
699	Catholic Chapel	52.11	617476	531881	448574	248547	115805	17851	4120	10070	61793	193162	348789	554767
720	Cadet Activities Div	24.24	287261	247440	208685	115628	53875	8305	1916	4685	28747	89862	162263	258087
722	Cadet Chapel	34.21	405386	349191	294499	163176	76029	11720	2705	6611	40569	126815	228988	364217
723	Garage	1.59	18793	16188	13652	7564	3525	543	125	306	1881	5879	10615	16884
725	Green House	2.04	24162	20813	17553	9726	4532	699	161	394	2418	7558	13648	21708
726	Filtration Plant	18.80	222828	191940	161877	89693	41791	6442	1487	3634	22299	69706	125867	200199
727	Arvin Gymnasium	736.33	8725206	7515707	6338548	3512073	1636380	252248	58211	142294	873167	2729456	4928545	7839102
735	Scott Barracks	104.22	1234952	1063762	897148	497093	231611	35703	8239	20140	123587	386323	697579	1109534
738	Sherman Barracks	131.41	1557114	1341265	1131187	626770	292031	45017	10388	25394	155827	487103	879556	1398978
740	Lee Barracks	90.63	1073871	925010	780129	432255	201401	31046	7164	17513	107467	335933	606590	964813
745	Washington Hall	660.00	7820747	6736625	5681491	3148010	1466752	226100	52177	127544	782654	2446520	4417649	7026497
747	Central Cadet Barracks	10.65	126180	108689	91665	50790	23665	3648	842	2058	12627	39472	71274	113365
751	Pershing Barracks	88.36	1047025	901885	760626	421449	196366	30270	6985	17075	104780	327535	591425	940692
752	Mahan Hall	430.47	5100889	4393798	3705613	2053212	956653	147468	34031	83187	510467	1595682	2881303	4582860
753	Bartlett Hall	288.87	3422965	2948470	2486661	1377813	641965	98959	22837	55823	342550	1070787	1933506	3075340
757	Library	126.88	1503420	1295014	1092181	605157	281961	43464	10030	24518	150453	470306	849226	1350738
	DHW AND MISC		6500000	6500000	7500000	12000000	15000000	16500000	20000000	20000000	15000000	12000000	6500000	6500000
	TOTAL		65905504	57670642	50655963	35911926	26141284	18217431	20396330	20968807	20944954	30583486	40055963	59872477
	TOTAL PLUS POWER PLANT CONSUMPTION		75791330	66321238	58254357	41298715	30062477	20950046	23455780	24114128	24086697	35171009	46064357	68853348

STANLEY CONSULTANTS, INC.

Future Steam Loads

Future steam loads for the USMA were estimated by the following methods:

- Future building plans, both additions to or demolition of buildings associated with the central heating system, were tabulated in square feet from the Master Plan Report.
- New buildings and additions were assigned a peak heating load of 30 Btu/sq ft.
- Demolished buildings were assigned a negative heating load value based on the existing building heating loads as shown in Table 1.
- Partially demolished buildings were also assigned a negative heating load value based on the ratio of the demolished portion of the building to the building's total heating load in square feet.
- For each building addition, a value was calculated for the heat transfer coefficient (uA) portion of the formula $Q = uA\Delta T$. Q is the peak heating load in Btu/hr; ΔT is the difference between the design indoor temperature of 68 °F and the design outdoor temperature of 4 °F.
- Predicted monthly steam use for each building addition was then calculated using the derived value for uA for that building and the normalized heating degree day calculation, on a 65 °F base.
- A peak steam load of 25,000 lb/h was included in the analysis to account for the Laundry Plant.
- The individual building future heating loads were added or subtracted from the total monthly steam load.

Table 2 presents the individual building heating loads for each building addition or demolition. The results of this analysis are presented in Table 3.

Air-Conditioning and Air-Conditioned Facilities

Table 4 presents a tabulation of all existing buildings equipped with large chilled water systems (installed capacity of greater than 60 tons). Existing building chilled water system equipment capacity includes 1705 tons of absorption chillers, 1840 tons of centrifugal chillers, and 590 tons of reciprocating chillers.

Future additional chilled water cooling capacity for the years 1990 to 2000 is included in Table 4, and was determined by dividing the future building areas from the Master Plan Report (300,000 sq ft) by a value of 250 sq ft/ton of cooling for new buildings. Based on the above data, the future additional load for new buildings was calculated as 1200 tons.

Steam Distribution and Condensate Return Systems

Superheated steam generated in the boilers at 160 psig and 425 °F is supplied to a common header system in the CPP. A portion of this high pressure steam is used within the power plant to supply three steam turbine/generators, two forced draft fan turbine drives, two boiler feed pump turbine drives, two fuel oil pump turbine drives, oil storage tank heaters, and heat tracing for the oil lines. The balance of the high pressure steam flows into the tunnel distribution lines.

Exhaust steam, at 12 psig, from the turbine/generators and steam turbine-driven forced draft fans, boiler feed pumps, and fuel oil pumps, enters the low pressure steam header. This header supplies low pressure steam to the deaerating feedwater heater, fuel oil heaters, fresh air heaters, fuel oil day tank heaters, and the low pressure steam distribution system. The low pressure steam header is maintained at a constant pressure of 12 psig by means of a pneumatic control valve. Pressure in excess of 13.5 psig will cause this control valve to open automatically and vent excess steam directly to the atmosphere. If the

Table 2

Predicted Peak Steam Demand

Building Number and Name		Sq Ft (gross)	Predicted Change[a] (lb/hr)	Predicted Total Pk St (lb/hr)	Predicted Total Pk St[b] (lb/hr)
	Existing Peak			185,000[C]	210,000[C]
1	Central Apartments	-40,000	-925		
	Bicentennial SCI Bldg	200,000	5,950		
600	Headquarters Bldg Add	1,000	30		
603	Officers Club Add	5,000	150		
605	Cullum Hall Add	4,340	130		
627	Storage Demo	-23,185	-540		
	New Marina	4,572	140		
635	Cadet Club Add	3,114	95		
663	Field House Add	28,000	835		
699	Catholic Chapel Add	50,000	1,490		
720	Cadet Activity Add	50,000	1,490		
727	Arvin Gym Add	10,500	315		
753	Bartlett Hall	47,400	1,410		
	Meddac Barracks	26,000	775		
	Future Peak			196,345[C]	221,345[C]

(a)Assuming a new building load of 30 Btu/sf-hr.
(b)Including the laundry boiler plant peak steam load of 25,000 lb/hr.
(c)Actual peak loads should be approximately 50,000 lb/hr lower per USMA, 15 March 1991.
Therefore, boiler capacity is somewhat oversized for this study including capital cost estimates for the boilers. Study results are not significantly affected.

pressure drops below 12 psig, a two-stage pressure reducing station located in the CPP will admit additional steam from the high pressure header.

The steam distribution system supplied from the CPP extends from U.S. Hotel Thayer at the south end of the Academy to Building No. 687 at the north end. This system contains lines for 160 psig high pressure steam, 12 psig low pressure steam, and condensate return.

Piping within the Central Cadet Area is contained in walk-through underground tunnels. Beyond the tunnel system, high pressure steam is reduced to 85 and 45 psig and distributed in direct buried insulated pipe. The high and low pressure steam lines in the tunnel system are connected to each major building in the Central Cadet Area. At each building, the high and low pressure steam systems are interconnected through a pressure reducing station to permit make-up steam to be fed from the high to the low pressure system as the load requires.

Table 3

Predicted Monthly Steam Consumption

USMA ENERGY STUDY
PREDICTED MONTHLY STEAM CONSUMPTION FOR HEATING, ABSORPTION COOLING AND DOMESTIC HOT WATER - FUTURE PLUS THE LAUNDRY
BASED ON NORMALIZED HEATING DEGREE DAYS, BASE 65 F

Bldg. No.	Building	Adjusted Heat Transfer Coefficient (MBtu/Hr-F)	JAN #'s Steam	FEB #'s Steam	MARCH #'s Steam	APRIL #'s Steam	MAY #'s Steam	JUNE #'s Steam	JULY #'s Steam	AUG #'s Steam	SEPT #'s Steam	OCT #'s Steam	NOV #'s Steam	DEC #'s Steam
	EXISTING TOTAL		65905504	57670642	50655963	35911926	26141284	18217431	20396330	20968807	20944954	30583486	40055963	59872477
	LAUNDRY BOILER PLANT		8720000	7190000	7571000	6925000	9369000	8549000	8231000	7257000	7704000	9200000	10398000	11890000
1	CENTRAL APARTMENTS	-14.45	-171227	-147491	-124390	-68922	-32113	-4950	-1142	-2792	-17135	-53564	-96720	-153838
	BICENTENNIAL SCI BLDG	92.97	1101659	948946	800316	443440	206612	31849	7350	17966	110248	344626	622286	989778
600	HEADQUASTERS BLDG ADD	0.47	5569	4797	4046	2242	1045	161	37	91	557	1742	3146	5004
603	OFFICERS CLUB ADD	2.34	27728	23884	20143	11161	5200	802	185	452	2775	8674	15663	24912
605	CULLUM HALL ADD	2.03	24055	20720	17475	9683	4511	695	160	392	2407	7525	13588	21612
627	STORAGE DEMO	-8.44	-100011	-86147	-72654	-40256	-18757	-2891	-667	-1631	-10008	-31286	-56492	-89854
	NEW MARINA	2.19	25951	22353	18852	10446	4867	750	173	423	2597	8118	14659	23315
635	CADET CLUB ADD	1.46	17537	15106	12740	7059	3289	507	117	286	1755	5486	9906	15756
663	FIELD HOUSE ADD	13.05	154637	133201	112339	62245	29002	4471	1032	2522	15475	48374	87349	138933
699	CATHOLIC CHAPEL ADD	23.28	275859	237619	200402	111039	51736	7975	1840	4499	27606	86295	155823	247844
720	CADET ACTIVITY ADD	23.28	275859	237619	200402	111039	51736	7975	1840	4499	27606	86295	155823	247844
727	ARVIN GYM ADD	4.92	58300	50218	42353	23467	10934	1685	389	951	5834	18238	32932	52379
753	BARTLETT HALL	22.03	261047	224860	189641	105077	48958	7547	1742	4257	26124	81662	147456	234536
	MEDDAC BARRACKS	12.11	143499	123607	104247	57761	26913	4149	957	2340	14361	44890	81057	128926
	FUTURE TOTAL		76725967	66669936	59752874	43682406	35904218	26827156	28641344	28260062	28859156	40440562	51640436	73649623
	FUTURE PLUS POWER PLANT CONSUMPTION		88234862	76670426	68715805	50234766	41289851	30851230	32937545	32499072	33188029	46506646	59386502	84697067

AVERAGE STEAM RATE PER MONTH

	JAN #/HR	FEB #/HR	MARCH #/HR	APRIL #/HR	MAY #/HR	JUNE #/HR	JULY #/HR	AUG #/HR	SEPT #/HR	OCT #/HR	NOV #/HR	DEC #/HR
EXISTING	88583	85819	68086	49878	35136	25302	27414	28184	29090	41107	55633	80474
EXISTING PLUS POWER PLANT CONSUMPTION	101870	98692	78299	57359	40407	29097	31527	32411	33454	47273	63978	92545
FUTURE PLUS LAUNDRY HEATING PLANT	103126	99211	80313	60670	48258	37260	38496	37984	40082	54356	71723	98991
FUTURE PLUS LAUNDRY & POWER PLANT	118595	114093	92360	69771	55497	42849	44271	43682	46094	62509	82481	113840
FUTURE PLUS LAUNDRY & POWER PLANT & CONVERT CENTIFUGAL AND RECIPROCATING CHILLERS TO ABSORPTION AND NEW ABSORPTION CHILLERS FOR FUTURE BUILDINGS.	118595	114093	92360	69771	71497	73849	90271	89682	77094	78509	82481	113840
FUTURE PLUS LAUNDRY & POWER PLANT & CONVERT ABSORPTION CHILLERS TO CENTRIFUGAL OR RECIPROCATING, AND NEW CENTRIFUGAL OR RECIPROCATING CHILLERS FOR FUTURE BUILDINGS.	118595	114093	92360	69771	47420	26700	20050	19460	29950	54430	82481	113840
FUTURE PLUS POWER PLANT CONSUMPTION, W/O LAUNDRY	105117	101789	80657	58710	41015	29194	31548	32464	33789	48289	65873	95461
FUTURE PLUS POWER PLANT PLUS CONVERT CENTRIFUGAL & RECIPROCATING CHILLERS TO NEW ABSORPTION W/O LAUNDRY	105117	101789	80657	58710	59170	65540	80480	81380	70140	66470	65873	95461

Table 4

Existing Buildings With Chilled Water Systems

Building No.	Building	Type of Refrigeration and Tons		
		Absorption	Centrifugal	Reciprocating
601	Thayer Hall	700		
603	Officer's Club	215		
606	Admissions/SJA/ Health Clinic		350	
655	Eisenhower Hall		800	240
674	Hotel Thayer			
745	Washington Hall	330		
752	Mahan Hall		290	
753	Bartlett Hall			350[a]
757	Library		400	
900	Keller Army Hospital	460		
Total		170	1840	590

Future Additional - 1200 Tons

(a) The Academy indicated (15 March 1991) that this chiller is an absorption unit. This change makes cogeneration options slightly more economically attractive than indicated by this study, but will likely not change the ranking of any plan.

Steam for the south end of the post is reduced to 85 psig at the Academic Science Building. The 85 psig steam line and condensate return line are direct buried in insulated conduit. A similar arrangement exists at the north end of the system with steam reduced to 85 psig beyond the connection point for the Cadet Activities Building service.

The low pressure steam piping does not extend beyond the Gym, Building 727. A number of buildings are supplied by 45 psig steam derived by pressure reduction from the high pressure main.

Condensate return piping extends from most buildings. However, approximately 30 percent of the condensate is lost. This loss is likely the result of corroded and leaking condensate return piping and/or condensate pump return units out of service.

Steam from the Laundry heating plant is distributed by a direct buried insulated conduit that also contains condensate return piping.

The low pressure steam distribution system was evaluated at the current 12 psig steam pressure and was found to be severely undersized. The undersized low pressure steam system prevents proper use of the existing steam turbine generators. For this reason, any refurbishing plan for the existing power plant should include increasing the steam pressure to 20 psig and replacing the low pressure steam distribution piping in the tunnels with larger piping.

The existing high pressure (160 psig) steam distribution system was also evaluated and found to be generously sized. The operating pressure for this system can be reduced to 100 psi with no piping changes. Reducing the pressure will help to optimize cogeneration options that use steam turbines.

The CPP is currently the central point for steam distribution. If a new site is used as the location for a new steam generating facility (see Chapter 4), the high pressure (100 psig) steam supply from the new facility would be tied into the existing steam distribution system at two locations. One location would be near the intersection of Brewerton Road and Thayer Road. The second tie-in would be made along Parke Road, just north of Building No. 727.

Steam Distribution

The piping, valves, joints, and insulation appear to be in good condition. Only minor valve stem leakage was observed at the locations inspected. Ground water was leaking into the tunnel and running down the floor in several places. These tunnel leaks should be repaired immediately to avoid deterioration to the point that pipe insulation gets wet or electrical lighting shorts out.

Globe valves are used in the steam distribution piping at many locations to prevent flow of steam in both directions and to limit development of steam supply loops. Some of these valves will need to be reversed or replaced with gate valves for any of those plans using one of the proposed new sites.

The steam distribution piping in the tunnels should last for 40 to 50 years, although piping insulation may require replacement if it gets wet or suffers mechanical abuse; replacement typically will be at intervals of 10 to 20 years.

The only repair needed for the steam distribution system within the tunnels is to eliminate ground water leaking into the tunnels. The reliability of the system can be maintained indefinitely if condensate returns and underground conduit systems are repaired or replaced as needed with high quality materials.

Direct buried steam distribution and condensate return systems typically are high maintenance facilities. Direct burial conduits for these systems may need replacement every 15 to 20 years unless the conduit coatings remain intact and cathodic protection is effective. Heat loss will be severe if ground water enters the underground conduit and saturates the pipe insulation. Severe external pipe corrosion will also occur if this situation persists. Repair or replacement of deteriorated conduit and piping is almost always more cost effective than allowing the condition to persist because of the severe heat loss and eventual total failure.

Condensate Returns

The carbon steel condensate return piping is likely experiencing severe corrosion due to existing power plant water treatment deficiencies (Stanley Consultants 1990). All condensate return piping (except piping recently replaced) should be inspected and replaced as the extent of corrosion dictates. Severe corrosion can be expected to continue until the power plant water treatment is improved or piping is replaced with stainless steel or fiberglass. Corrosion of carbon steel pipe can be greatly reduced and condensate return reliability can be improved by using adequate water treatment. The expected life for carbon steel pipe used for condensate return piping under ideal conditions should be 20 to 25 years. Unless stainless steel or fiberglass is used for condensate return piping, some corrosion should be expected.

Boiler water makeup averages 25 to 30 percent, which is extremely high for a steam distribution system used primarily for space heating and air-conditioning. Makeup should be between 8 and 15 percent for a system of this type. The higher percentage of makeup water indicates leaking condensate return piping and/or condensate pump return units out of service. Lost condensate must be replaced, which requires chemical treatment and heating of raw water.

Existing Facilities Electrical Services and Loads

The Academy is served by 13.2 kilovolt (kV) and 4.16 kV primary distribution services. Electrical service from Orange and Rockland Utilities, Inc. is delivered at 34.5 kV via the Delafield Substation and the Wilson Gate service.

Delafield Substation

The Delafield Substation has a double incoming service configuration from two 34.5-kV overhead lines. Presently there are two 34.5 kV X 69 kV-13.8 kV transformers with load tap changers. Both transformers are of the dual primary voltage type suitable for either 34.5 kV or 69 kV incoming voltage. One is rated 7500/9375 kVA OA/FA, while the other is rated 12,000/16,000/20,000 kVA OA/FA/FFA. Both are connected primary delta and secondary grounded wye. The transformers serve a lineup of 13.2-kV, metal-clad switchgear. This switchgear provides feeders to Substations B, C, and D and primary selective feeders serving multiple building service transformer installations at 13.2 kV.

Wilson Gate Service Entrance

This service provides a 34.5-kV underground feeder to the power plant.

Power Plant Substation

The power plant has a lineup of 4.16-kV metal-clad switchgear used for the generation bus and distribution to the central academic area. This switchgear receives services from Wilson Gate via two 1960 kVA 34.5 kV-4.16 kV transformers located adjacent to the power plant.

Substation B

This substation, located adjacent to the power plant, includes a 13.2 kV-4.16 kV transformer to provide a tie circuit between the Delafield Substation and the power plant 4.16 kV switchgear.

Substation C

This substation, located in Building 715, includes a 2000 kVA 13.2 kV-4.16 kV transformer and 4.16-kV metal-clad switchgear. This substation provides 4.16 kV services to building service transformers in this area.

Substation D

This substation, located at Building 727, includes a 2500 kVA transformer and 4.16 kV metal-clad switchgear. The substation provides 4.16 kV services to building service transformers in this area.

Alternative Energy Systems

The various plans proposed herein for heating and cooling the Academy have various levels of impact on the primary electrical distribution system.

Power Plant

In nearly all the alternative energy plans, the substation and 4.16 kV distribution equipment at the power plant will be replaced. This equipment is nearing the end of its useful service life and should be replaced with new equipment for long term service reliability. The cost estimates detail the changes required for installation of new transformers and switchgear.

The plans that propose relocation of the CPP (see Chapter 4) have a substantial impact on the underground primary distribution system in the central academic area. Since previous development of this area has resulted in the routing of feeders from the power plant, it would be best to plan a new electrical distribution center within the existing power plant building.

Delafield Substation Improvements

The plans that propose a new central power and chiller plant at one of the undeveloped sites require that the new plant be connected to the Delafield Substation. This would require adding circuit breakers to the 13.2-kV, metal-clad switchgear. The plans that propose large capacity, third-party financed cogeneration interconnections would require a new substation and new power lines from the cogeneration plant to a power company substation.

Projected Electric Loads

The predicted electric loads for the year 2002 are shown in Tables 5 through 9 for each of the chiller alternatives evaluated in this study.

The present monthly loads listed were taken from 1989 Orange and Rockland billings (minimum kW was derived from standard load duration curves). Monthly load additions were estimated from new facilities projected in the USMA Master Plan.

Table 5

Existing Chiller Equipment (Option A)

Month	kWh	Peak kW	Avg kW	Min kW
Dec Present	5,651,200	12,070	8,292	5,339
Dec Additions	718,000	1,450	965	650
Dec Projected	6,369,200	13,520	9,257	5,989
Nov Present	6,018,000	10,450	7,835	5,302
Nov Additions	694,800	1,450	965	650
Nov Projected	6,712,800	11,900	8,800	5,952
Oct Present	6,402,600	13,580	8,335	4,981
Oct Additions	766,300	1,550	1,030	700
Oct Projected	7,168,900	15,130	9,365	5,681
Sep Present	6,922,800	13,990	9,615	6,254
Sep Additions	792,000	1,650	1,100	740
Sep Projected	7,714,800	15,640	10,715	6,994
Aug Present	6,790,800	14,130	9,755	6,373
Aug Additions	818,400	1,650	1,100	740
Aug Projected	7,609,200	15,780	10,855	7,113
Jul Present	6,829,800	13,230	9,180	6,006
Jul Additions	818,400	1,650	1,100	740
Jul Projected	7,648,200	14,880	10,280	6,746
Jun Present	5,529,600	12,150	7,945	5,030
Jun Additions	792,000	1,650	1,100	740
Jun Projected	6,321,600	13,800	9,045	5,770
May Present	5,362,000	11,220	7,695	5,135
May Additions	766,300	1,150	1,030	700
May Projected	6,128,300	12,770	8,725	5,835
Apr Present	5,568,200	11,130	7,732	4,833
Apr Additions	694,800	1,450	965	650
Apr Projected	6,263,000	12,580	8,697	5,483
Mar Present	5,203,200	11,420	7,627	4,349
Mar Additions	718,000	1,450	965	650
Mar Projected	5,921,200	12,870	8,592	4,999
Feb Present	6,206,000	11,932	8,004	4,884
Feb Additions	648,500	1,450	965	650
Feb Projected	6,854,500	13,382	8,969	5,534
Jan Present	5,148,400	10,516	7,320	4,700
Jan Additions	718,000	1,450	965	650
Jan Projected	5,866,400	11,966	8,285	5,350
Yearly Present	71,632,600			
Yearly Additions	8,945,500			
Yearly Projected	80,578,100			

Table 6

All Motor Driven Water Chillers Replaced With Absorption (Options B and E)

Month	kWh	Peak kW	Avg kW	Min kW
Dec Present	5,651,200	12,070	8,292	5,339
Dec Additions	718,000	1,450	965	650
Dec Projected	6,369,200	13,520	9,257	5,989
Nov Present	6,018,000	10,450	7,835	5,302
Nov Additions	694,800	1,450	965	650
Nov Projected	6,712,800	11,900	8,800	5,952
Oct Present	6,402,600	13,580	8,335	4,981
Oct Additions	297,600	600	400	270
Oct Projected	6,700,200	14,180	8,735	5,251
Sep Present	6,922,800	13,990	9,615	6,254
Sep Additions	180,000	375	250	170
Sep Projected	7,102,800	14,365	9,725	6,424
Aug Present	6,790,800	14,130	9,755	6,373
Aug Additions	-22,300	-50	-30	-20
Aug Projected	6,768,500	14,080	9,725	6,353
Jul Present	6,829,800	13,230	9,180	6,006
Jul Additions	-22,300	-50	-30	-20
Jul Projected	6,807,500	13,180	9,150	5,986
Jun Present	5,529,600	12,150	7,945	5,030
Jun Additions	180,000	375	250	170
Jun Projected	5,709,600	12,525	8,195	5,200
May Present	5,362,000	11,220	7,695	5,135
May Additions	297,600	600	400	270
May Projected	5,659,600	11,820	8,095	5,405
Apr Present	5,568,200	11,130	7,732	4,833
Apr Additions	694,800	1,450	965	650
Apr Projected	6,263,000	12,580	8,697	5,483
Mar Present	5,203,200	11,420	7,627	4,349
Mar Additions	718,000	1,450	965	650
Mar Projected	5,921,200	12,870	8,592	4,999
Feb Present	6,206,000	11,932	8,004	4,884
Feb Additions	648,500	1,450	965	650
Feb Projected	6,854,500	13,382	8,969	5,534
Jan Present	5,148,400	10,516	7,320	4,700
Jan Additions	718,000	1,450	965	650
Jan Projected	5,866,400	11,966	8,285	5,350
Yearly Present	71,632,600			
Yearly Additions	5,102,700			
Yearly Projected	76,737,300			

Table 7

All Absorption Chillers Replaced With Motor Driven in Central Chiller Plant (Option C)

Month	kWh	Peak kW	Avg kW	Min kW
Dec Present	5,651,200	12,070	8,292	5,339
Dec Additions	718,000	1,450	965	650
Dec Projected	6,369,200	13,520	9,257	5,989
Nov Present	6,018,000	10,450	7,835	5,302
Nov Additions	694,800	1,450	965	650
Nov Projected	6,712,800	11,900	8,800	5,952
Oct Present	6,402,600	13,580	8,335	4,981
Oct Additions	855,600	1,715	1,150	775
Oct Projected	7,258,200	15,295	9,485	5,756
Sep Present	6,922,800	13,990	9,615	6,254
Sep Additions	910,800	1,890	1,265	850
Sep Projected	7,833,600	15,880	10,880	7,104
Aug Present	6,790,800	14,130	9,755	6,373
Aug Additions	982,100	1,975	1,320	890
Aug Projected	7,772,900	16,105	11,075	7,263
Jul Present	6,829,800	13,230	9,180	6,006
Jul Additions	982,100	1,975	1,320	890
Jul Projected	7,811,900	15,205	10,500	6,896
Jun Present	5,529,600	12,150	7,945	5,030
Jun Additions	910,800	1,890	1,265	890
Jun Projected	6,440,400	14,040	9,210	5,880
May Present	5,362,000	11,220	7,695	5,135
May Additions	855,600	1,715	1,150	775
May Projected	6,217,600	12,935	8,845	5,910
Apr Present	5,568,200	11,130	7,732	4,833
Apr Additions	694,800	1,450	965	650
Apr Projected	6,263,000	12,935	8,697	5,483
Mar Present	5,203,200	11,420	7,627	4,349
Mar Additions	718,000	1,450	965	650
Mar Projected	5,921,200	12,870	8,592	4,999
Feb Present	6,206,000	11,932	8,004	4,884
Feb Additions	648,500	1,450	965	650
Feb Projected	6,854,500	13,382	8,969	5,534
Jan Present	5,148,400	10,516	7,320	4,700
Jan Additions	718,000	1,450	965	650
Jan Projected	5,866,400	11,966	8,285	5,350
Yearly Present	71,632,600			
Yearly Additions	9,689,100			
Yearly Projected	81,321,700			

Table 8

All Absorption Chillers Replaced With Motor Driven in Existing Buildings (Option D)

Month	kWh	Peak kW	Avg kW	Min kW
Dec Present	5,651,200	12,070	8,292	5,339
Dec Additions	718,000	1,450	965	650
Dec Projected	6,369,200	13,520	9,257	5,989
Nov Present	6,018,000	10,450	7,835	5,302
Nov Additions	694,800	1,450	965	650
Nov Projected	6,712,800	11,900	8,800	5,952
Oct Present	6,402,600	13,580	8,335	4,981
Oct Additions	1,071,400	2,150	1,440	970
Oct Projected	7,474,000	15,730	9,775	5,951
Sep Present	6,922,800	13,990	9,615	6,254
Sep Additions	1,224,000	2,540	1,700	1,145
Sep Projected	8,146,800	16,530	11,315	7,399
Aug Present	6,790,800	14,130	9,755	6,373
Aug Additions	1,413,600	2,840	1,900	1,280
Aug Projected	8,204,400	16,970	11,655	7,653
Jul Present	6,829,800	13,230	9,180	6,006
Jul Additions	1,413,600	2,840	1,900	1,280
Jul Projected	8,243,400	16,070	11,080	7,286
Jun Present	5,529,600	12,150	7,945	5,030
Jun Additions	1,224,000	2,540	1,700	1,145
Jun Projected	6,753,600	14,690	9,645	6,175
May Present	5,362,000	11,220	7,695	5,135
May Additions	1,071,400	2,150	1,440	970
May Projected	6,433,400	13,370	9,135	6,105
Apr Present	5,568,200	11,130	7,732	4,833
Apr Additions	694,800	1,450	965	650
Apr Projected	6,263,000	12,580	8,697	5,483
Mar Present	5,203,200	11,420	7,627	4,349
Mar Additions	718,000	1,450	965	650
Mar Projected	5,921,200	12,870	8,592	4,999
Feb Present	6,206,000	11,932	8,004	4,884
Feb Additions	648,500	1,450	965	650
Feb Projected	6,854,500	13,382	8,969	5,534
Jan Present	5,148,400	10,516	7,320	4,700
Jan Additions	718,000	1,450	965	650
Jan Projected	5,866,400	11,966	8,285	5,350
Yearly Present	71,632,600			
Yearly Additions	11,610,100			
Yearly Projected	83,242,700			

Table 9

All Energy Requirements Supplies by Electrical Energy

Month	kWh	Peak kW	Avg kW	Min kW
Dec Present	5,651,200	12,070	8,292	5,339
Dec Additions	22,297,100	48,575	32,328	21,775
Dec Projected	27,948,300	60,645	40,620	27,114
Nov Present	6,018,000	10,450	7,835	5,302
Nov Additions	15,825,300	31,255	20,800	14,010
Nov Projected	21,843,300	41,705	28,635	19,312
Oct Present	6,402,600	13,580	8,335	4,981
Oct Additions	12,920,300	23,955	16,045	10,808
Oct Projected	19,322,900	37,535	24,380	15,789
Sep Present	6,922,800	13,990	9,615	6,254
Sep Additions	9,679,700	20,085	13,445	9,055
Sep Projected	16,602,400	34,075	23,060	15,309
Aug Present	6,790,800	14,130	9,755	6,373
Aug Additions	9,693,700	20,420	13,660	9,502
Aug Projected	16,484,500	34,550	23,415	15,875
Jul Present	6,829,800	13,230	9,180	6,006
Jul Additions	9,805,400	19,700	13,180	8,879
Jul Projected	16,635,200	32,930	22,360	14,885
Jun Present	5,529,600	12,150	7,945	5,030
Jun Additions	9,084,200	19,310	12,925	8,705
Jun Projected	14,613,800	31,460	20,870	13,735
May Present	5,362,000	11,220	7,695	5,135
May Additions	11,591,200	24,450	16,375	11,030
May Projected	16,953,200	35,670	24,070	16,165
Apr Present	5,568,200	11,130	7,732	4,833
Apr Additions	13,493,600	28,155	18,738	12,621
Apr Projected	19,061,800	39,285	26,470	17,454
Mar Present	5,203,200	11,420	7,627	4,349
Mar Additions	18,225,400	39,620	26,368	17,760
Mar Projected	23,428,600	51,040	33,995	22,109
Feb Present	6,206,000	11,932	8,004	4,884
Feb Additions	20,182,600	39,855	26,526	17,865
Feb Projected	26,388,600	51,787	34,530	22,749
Jan Present	5,148,400	10,516	7,320	4,700
Jan Additions	23,198,500	49,155	32,715	22,035
Jan Projected	28,346,900	59,671	40,035	26,735
Yearly Present	71,632,600			
Yearly Additions	259,239,600			
Yearly Projected	330,872,200			

3 COGENERATION BACKGROUND

Technical Background

Cogeneration is the simultaneous production of electricity and useful thermal energy. Typically, electricity is generated to supply part or all of the cogenerator's power requirements, while waste heat from the prime mover is recovered in the form of hot water and/or steam, resulting in a combined efficiency in energy production that is greater than would be possible with separate generation of electricity and steam.

Although a number of technologies may be used for cogeneration, gas turbine and reciprocating engine generating units with waste heat recovery equipment are usually considered when small to medium-size electric generating units are required. These systems use convenient gaseous and liquid fuels and are efficient, simple in operation, and flexible in meeting the electrical and thermal demands. Medium to large-sized systems would use topping cycle steam turbines.

Gas turbine cogeneration systems typically are designed with overall thermal efficiencies greater than 60 percent. Normally 20 to 30 percent of the energy input is recovered as electric output and 30 to 50 percent is recovered as thermal output. Reciprocating engine cogeneration systems may achieve overall thermal efficiencies of 50 to 75 percent, depending on whether low grade thermal energy can be used. Electric output accounts for 25 to 35 percent of fuel input and thermal output accounts for 15 to 40 percent. In comparison, modern coal-fired electric generating units operate at about 35 percent thermal efficiency. By selecting a prime mover and a thermal recovery system appropriate for the electric and thermal loads of the facility, efficient and economic production of electricity may be achieved. For gas turbine applications, two variables (in addition to initial cost) have significant impact on the economic feasibility of the cogeneration system. The first important parameter is the heat rate of the gas turbine; heat rate is defined as the heating value of the fuel input in Btu/kWh of generator output. Other factors being equal, the lower the heat rate, the more attractive the economics of the project. The second important parameter is exhaust temperature. Gas turbines with high exhaust temperatures provide more efficient waste heat recovery. Therefore, a combination of low heat rate and high exhaust temperature is desirable for cogeneration with gas turbines.

Reciprocating engines are characterized by lower heat rates over a range of loadings compared to gas turbines. Also, the proportion of energy output in the form of electricity is higher relative to the thermal heat recovered. Therefore, electric cost savings per Btu of fuel input are usually greater than for gas turbines.

A major component in a cogeneration system is the thermal energy recovery equipment, which should be designed to extract the maximum possible amount of energy from the exhaust and cooling systems. The most common device for recovering exhaust heat is either a waste heat boiler or waste heat recovery silencer. These devices can produce either hot water or steam. Since steam production is more common, this type of device is often called a heat recovery steam generator (HRSG).

The extent to which recoverable heat from reciprocating engines is in the form of steam or hot water depends on the engine design and the heat balance. Heat can be recovered from the exhaust gas in a HRSG as high pressure steam, while recovery from engine jacket water can be as hot water or as low pressure steam. With an ebulliently-cooled reciprocating engine (250 °F jacket water), cooling water waste heat is recovered as low pressure steam (15 psig or lower). Much of the recoverable heat, which is produced from engine lube oil and charge air cooling systems, may be low grade. The selection of

reciprocating engines also depends on their operating parameters such as engine speed and brake mean effective pressure (bmep) since they affect engine maintenance, length of life, and reliability of service.

Several methods of using topping cycle steam turbines in cogeneration systems are available. Steam generated in the boiler is passed through a steam turbine-generator set to produce electricity. Steam, at various temperatures and pressures, can be extracted from the turbine. Temperature, pressure, and quantity of extraction steam are determined by the turbine design. Extraction steam, along with turbine exhaust, can be used for the owner's process or heating requirements or exported to other nearby industries. Alternatively, turbine exhaust can be condensed in a condenser.

Regulatory Considerations

A cogeneration plant must satisfy the requirements of a Qualifying Facility as specified by the 1978 Public Utilities Regulatory Policy Act (PURPA) in order to require local electric utility interconnection and parallel operation with the utility.PURPA requires utilities to interconnect with qualifying cogenerators and to provide maintenance power, backup power, and supplementary power without penalty. PURPA also requires that a cogeneration facility achieve a minimum operating efficiency of 42.5 percent, computed in accordance with specified procedures, in order to be certified as a Qualifying Facility.

Third-Party Financing

An increasingly popular alternative to self-ownership and financing of a cogeneration facility by the user is "third-party" ownership, which is often known as "third-party" financing. The three parties involved are the utility, the user of the cogeneration plant, and the entity that finances and owns the plant (investor). Either the investor or the user may be the operator of the plant, depending on the preferences of the parties involved. Also, the investor and the user may jointly own the plant.

Public Law 97-214, Military Construction Codification Act, Section 2394, permits the military services to enter into long term contracts for the purchase of energy or fuel from production facilities on or off installation property. The law requires contract approval through functional channels up to the Secretary of Defense and notification of contract terms to the U.S. Congress. Congress has expressed strong interest in and support of this concept. The U.S. Army Corps of Engineers (USACE) Office of the Assistant Chief of Engineers is the program center of competence and provides the overall guidance for implementing goals and objectives. The Huntsville Division, USACE is the center of expertise for support of the program within the Army and for development of a management plan. Army use of this contract approach can reduce Military Construction, Army (MCA) funding requirements for energy plants, operating and maintenance labor requirements, large rehabilitation projects (e.g., Backlog of Maintenance and Repair [BMAR]) at energy plants, and stockpile fuel purchase inventories.

The principal advantages to the user of third-party financing are expanded access to capital at equal or lower cost than financing by the user from conventional sources, and the fact that the investor, not the user, assumes project financial responsibility.

Third-party financing may also result in a reallocation of risk between the parties. Where the user is an agency of the Federal government, third-party financing may still be an attractive source of capital if the third party is able to make use of certain tax incentives that would otherwise be lost.

Note that the benefits of third-party financing were reduced by the 1986 Tax Reform Act, which eliminated the investment tax credit and the energy tax credit. The Act also modified the Accelerated Cost

Recovery System (ACRS) for depreciation and reduced the associated tax benefits. For study purposes, the Asset Depreciation Range (ADR) Class Life of cogeneration facilities is assumed to be 20 to 24 years. This qualifies the facility's costs for 15-year tax life and 150 percent declining balance depreciation. This tax depreciation basis is incorporated in the computer feasibility model.

Four basic approaches have been used to structure a third-party financing arrangement:

1. Conventional Lease Financing. A third-party investor finances and owns the project and leases it back to the user. At the end of the lease period, the user could purchase the asset, renew the lease, or withdraw from further involvement in the transaction.

2. Joint Ventures. The user and the third-party investor form a partnership to finance and own the project. The investor provides the cash for the project (typically highly leveraged, i.e., low equity/high debt) and, in return, receives tax benefits and an agreed share of the return from the project.

3. Shared-Savings Plans. The third-party investor finances and owns the project. The investor then receives an agreed share of the return from the project.

4. Energy Services Contracts. The third-party investor finances and owns the project. The investor then sells the steam and electric output of the project at agreed prices. This arrangement does not tie the price to energy-cost savings as in the shared savings plan.

When the user is a department of the government, conventional lease financing and joint ventures are likely to be irrelevant. However, shared-savings plans and energy services contracts may be attractive to the government as a risk-sharing mechanism. It should be noted that third-party financing schemes may result in increased costs to USMA because the third party must necessarily have access to capital at higher cost than the government and must also pay both Federal and state income taxes on any profits earned through the arrangement. On the other hand, it is possible that the third party's capital costs could be reduced by its ability through the plan to take advantage of certain Federal income tax investment inducements that would otherwise be lost.

Other potential advantages of third-party ownership may be lower fuel costs, lower construction costs, and lower operation and maintenance expenses. For example, a single third party may have subsidiaries that own gas reserves and may engineer, construct, and operate cogeneration projects. In these situations, the third party would have greater flexibility and control over profitability than would the user. The extent to which any of these potential additional advantages are realized by the user depends on the particular contractual arrangements.

From an economic point of view, a user should not accept a third-party arrangement unless the cash savings it offers are greater than those with user ownership in excess of its minimum acceptable rate of return. Other factors that should be considered carefully before entering into third-party financing arrangements are applicable IRS regulations as they affect the third party, and the relative risks of self-ownership and alternative third-party arrangements.

One other reason third-party financing may be an attractive alternative relates to the procedures used by the government in constructing its budget. The Federal budget is concerned only with the timing of cash outflows and does not distinguish between capital and operating items. The use of third-party financing for an energy supply project at USMA can have the effect of transforming a large Federal cash outflow at the beginning of the project with small annual outflows over its life into a series of annual Federal cash outflows. This revised payment stream may be incorporated more readily into the Federal budgeting process.

4 STUDY ALTERNATIVES

Background

This section presents a summary of the 27 base plans, with various options for steam distribution and chilled water production, that were evaluated during this study. Combining the base plans with the various options resulted in a total of 68 individual plans. In addition, four new sites were considered for location of a new central heating and chilled water plant (Figure 1).*

Initial technical and economic screening of these 68 plans resulted in selection of 13 plans for more rigorous analysis. Schematic diagrams for these 13 plans were developed and general arrangement drawings for 6 of the 13 plans were prepared. Figures 2 through 20 are schematic diagrams for Plans 1 through 6, and 9 through 15 (Plans 7 and 8 were not used), and general arrangement drawings for Plans 1, 2, 3, 11, 12, and 13.

Figure 21 is a schematic drawing for coal, ash, and flue gas treatment systems and applies to all coal-fired plans. Figures 22 and 23 present typical schematic layouts for central chilled water plants using, respectively, centrifugal and absorption type chillers.

Figure 24 shows proposed power plant Sites 1, 2, 3, and 4 along with the existing steam distribution system and the proposed routing for a new steam line connecting the existing CPP and Laundry to the proposed Site 1 Power Plant. Figure 25 shows proposed Power Plant Sites 1, 2, 3, and 4 along with the existing electrical distribution system and the proposed routing for a new overhead pole line connecting the existing Delafield Substation "A" to the proposed Site 1 Power Plant.

Plans 1 through 16 and their various options are generally within the category of the conventional approach with constrained budgets, reasonable capital improvements, and payback. Plans 17 through 27 are in the category of exotic (fuel/system) approach with unproven methods or arrangement still under development, or the category of innovative engineering approach with generally known and used systems with ideal locations and distribution methods and unconstrained capital budget.

It should be noted that considerable duplication occurs between certain components of each plan described below. However, each plan is described in full so the description of each plan stands alone with no cross-reference required.

Plan Descriptions

Plan 1 - Existing Steam Heat and Cogeneration-Refurbish Existing Plant-Gas/Oil-Fired Boilers

Refer to Figure 2 for the schematic diagram and Figure 3 for the general arrangement drawing. This plan consists of replacing the two existing 200,000 lb/h boilers with two new gas/oil-fired 150,000 lb/h boilers to generate steam at 600 psig and 750 °F. Selective catalytic reduction (SCR) equipment is included to control emission of nitrogen oxides. SCR equipment would be furnished by the boiler manufacturer. This plan assumes existing Boiler No. 3 will have been replaced before 1995 by a new 80,000 lb/h boiler capable of producing steam at 600 psig, 750 °F. Natural gas for the boilers is assumed

*Figures are located at the end of the chapter, beginning on page 56.

to be supplied by Central Hudson Gas and Electric Co. If gas from an independent supplier is used, it will also be transported through Central Hudson gas mains. No. 2 fuel oil will be the backup fuel.

Two new 3000 kW turbine/generators equipped with auto extraction at 100 psig and 20 psi exhaust will also be installed to replace the existing turbine/generators. The existing 12 psi steam system will be upgraded to 20 psi to obtain additional electric generation. The upgrade will include replacement of most of the campus low pressure mains with larger pipe.

Two alternatives for steam distribution and condensate collection were considered. One is to use the existing steam distribution and condensate return systems except for replacing the low pressure steam mains as indicated above. The second alternative is to replace the entire steam distribution and condensate return systems. The Laundry heating plant and existing distribution system it supplies will not be connected to the main campus distribution system for either alternative.

Two options to provide chilled water were considered for this plan. The first option is to retain the existing chillers and add new absorption chillers for new buildings (Option A). The second option is to replace existing centrifugal and reciprocating chillers at the buildings with new absorption chillers and add new absorption chillers for new buildings (Option E).

As part of the power plant upgrade, the plant electrical distribution system should be replaced. It is approaching the end of its useful service life. Long-term reliability of the electrical distribution system requires installing new equipment. Substation "B" and the electrical distribution equipment at the central plant would be replaced as follows:

- Two 1960 kVA 34.5 kV - 4.16 kV transformers for the Wilson Gate service,
- 4.16 kV metal-clad generator and campus distribution switchgear,
- Plant 480/277-volt unit substation,
- Plant 480-volt motor control centers,
- Plant and substation medium and low voltage conduits and cables,
- One 4200 kVA 13.2 kV - 4.16 kV transformer for the Delafield Substation tie circuit, and
- Upgrade the tie circuit between Substation "B" and the Delafield Substation.

If the option of replacing centrifugal chillers with absorption chillers is used, the electrical system capacity required in the central plant will be reduced.

Plan 2 - Existing Steam Heat and Cogeneration-Refurbish Existing Plant-Coal Fired

Refer to Figure 4 for the schematic diagram and Figure 5 for the general arrangement drawing. This plan replaces the existing boilers with two 150,000 lb/h and one 80,000 lb/h boilers to generate steam at 600 psig and 750 °F. Two new 3000 KW turbine/generators equipped with auto extraction at 100 psig and 20 psi exhaust will also be installed. The existing 12 psi steam system will be upgraded to 20 psi to obtain additional electric generation. This will include replacing most of the campus low pressure mains with larger pipe.

A coal/water mixture will be used as fuel for the boilers. Prices of these mixtures were obtained from commercial suppliers. Since space for conventional coal storage and handling systems is limited at the present power plant site, the existing oil storage tanks can be modified and reused for coal/water storage. The coal/water mixture will be supplied from a private producer. Agitators will be required for the fuel storage tanks and new burners for the boilers will be required, as well as new fuel pumps and piping. In addition, complete emission control systems consisting of baghouses for control of particulate and a spray dry flue gas desulfurization (FGD) system for control of sulfur dioxide emissions will be

required, along with ash handling and FGD waste storage systems. Ash and FGD waste will be returned to a coal mine for disposal. In addition, lime handling and storage equipment will be added.

Two alternatives for steam distribution and condensate collection were considered. One is to use the existing steam distribution and condensate return systems except for replacing the low pressure steam mains as indicated above. The second alternative is to replace the entire steam distribution and condensate return systems. The Laundry heating plant and existing distribution system it supplies will not be connected to the main campus distribution system for either alternative.

Options for supplying chilled water include retaining all existing chillers and adding new absorption chillers for new buildings (Option A) or replacing all existing centrifugal and reciprocating chillers with new absorption chillers, as well as using new absorption chillers for new buildings (Option E).

As part of the power plant upgrade, the plant electrical distribution system should be replaced. It is approaching the end of its useful service life. Long-term reliability of the electrical distribution system requires installing new equipment. Substation "B" and the electrical distribution equipment at the central plant would be replaced as follows:

- Two 1960 kVA 34.5 kV - 4.16 kV transformers for the Wilson Gate service,
- 4.16 kV metal-clad generator and campus distribution switchgear,
- Plant 480/277-volt unit substation,
- Plant 480-volt motor control centers,
- Plant and substation medium and low voltage conduits and cables,
- One 4200 kVA 13.2 kV - 4.16 kV transformer for the Delafield Substation tie circuit, and
- Upgrade the tie circuit between Substation "B" and the Delafield Substation.

The addition of coal and ash handling systems, larger boiler fans, and pollution control equipment will require additional motor control centers and a unit substation beyond those required for a gas/oil-fired plant.

If the option of replacing centrifugal chillers with absorption chillers is used, the electrical system capacity required in the central plant will be reduced.

Plan 3 - New Gas/Oil-Fired Central Steam Plant

Refer to Figure 6 for the schematic diagram and Figure 7 for the general arrangement drawing. The new plant will be located at one of four potential sites as shown on Figure 1. All factors associated with site development, including adding sewers, water supply, access roads, power, and visibility from the remainder of the campus are considered. Natural gas for the boilers is assumed to be supplied by Central Hudson Gas and Electric Co. If gas from an independent supplier is used, it will also be transported through Central Hudson gas mains. No. 2 fuel oil will be the backup fuel.

Two alternatives for steam distribution and condensate collection were considered. One is to use the existing steam distribution and condensate return systems with new piping as required to connect to the new plant. The second alternative is to replace the entire steam distribution and condensate return systems. The Laundry heating plant and its existing distribution system will be connected to the new plant distribution system.

The options for providing chilled water to the campus include:

- Use the existing chillers and use centrifugal chillers for all new buildings (Option A). Existing chillers include both absorption and centrifugal types,

- New central centrifugal chiller plant (Option C), and
- Replace all existing absorption chillers with centrifugal type chillers and use centrifugal chillers for all new buildings (Option D).

If a new central chilled water plant is used, it will be included as part of the boiler plant, and a chilled water distribution system will be installed to buildings with chilled water systems. Thermal storage is not considered feasible for USMA because of the configuration of Orange County and Rockland County electrical rates.

This plan includes installing three new 125,000 lb/h gas/oil-fired boilers, generating steam at 100 psig and 400 °F. Selective catalytic reduction (SCR) equipment will be provided by the boiler manufacturer to control nitrogen oxide emissions. Oil storage and handling facilities will be required.

A separate incinerator plant to burn solid waste and generate steam can be included with this plan as an option. The feasibility and costs of this option are discussed by Griggs (May 1994).

As part of the power plant replacement, the plant electrical distribution system should be replaced. It is approaching the end of its useful service life. Long-term reliability of the electrical distribution system requires installing new equipment. Replace Substation "B" and the electrical distribution equipment at the central plant with:

- Two 1960 kVA 34.5 kV - 4.16 kV transformers for the Wilson Gate service,
- 4.16 kV metal-clad generator and campus distribution switchgear,
- Plant 480/277-volt unit substation,
- Plant 480-volt motor control centers,
- Plant and substation medium and low voltage conduits and cables,
- One 4200 kVA 13.2 kV - 4.16 kV transformer for the Delafield Substation tie circuit, and
- Upgrade the tie circuit between Substation "B" and the Delafield Substation.

Constructing a new central plant will require substantially less electrical system capacity at the old power plant; the equipment will be removed. A portion of the old plant should be developed as the location for the central campus distribution switchgear, even if the remainder of the plant is developed for other uses.

Locating a new plant on any of the proposed plant sites will require installing a new tie circuit between the new plant and the Delafield Substation:

- Two new breakers in the Delafield Substation metal-enclosed switchgear, and
- 15 kV cables and concrete-encased duct bank and cable vaults.

Plan 4 - New Coal-Fired Central Steam Plant

Refer to Figure 8 for the schematic diagram for Plan 4. Four sites, as shown in Figure 1, were considered for this plan. Factors associated with site development, including adding sewers, water supply, access roads, power, and visibility are also considered.

Two alternatives for steam distribution and condensate collection were considered. One will use the existing steam distribution and condensate return systems with new piping as required to connect to the new plant. The second alternative will replace the entire steam distribution and condensate return systems. The Laundry heating plant and its existing distribution system will be connected to the new plant distribution system.

The options for providing chilled water to the campus include:

- Use the existing (absorption and centrifugal) chillers and use centrifugal chillers for all new buildings (Option A),
- New central centrifugal chiller plant (Option C), and
- Replace all existing absorption chillers with centrifugal type chillers and use centrifugal chillers for all new buildings (Option D).

If a new central chilled water plant is used, it will be included as part of the boiler plant, and a chilled water distribution system will be installed to buildings with chilled water systems.

The coal-fired plant includes three 125,000 lb/h boilers generating steam at 100 psig and 400 °F. The steam generators will consist of either fluidized bed combustion units (FBC) or stoker-fired boilers. With the FBC, only a baghouse is required for particulate emissions control. For the stoker-fired boiler, both a dry scrubber for control of sulfur dioxide emissions and a baghouse for control of particulate emissions are required.

Coal storage and handling equipment, ash storage and handling equipment, and lime or limestone storage and handling equipment are also required. For either the FBC or stoker-fired options, a new coal pile run-off collection and treatment system will be required except at Site 2 where coal would be stored in silos.

A separate incinerator plant to burn solid waste and generate steam can be included with this plan as an option. The feasibility and costs of this option are discussed by Griggs (May 1994).

As part of the power plant replacement, the plant electrical distribution system should be replaced. It is approaching the end of its useful service life. Long-term reliability of the electrical distribution system requires installing new equipment. Replace Substation "B" and the electrical distribution equipment at the central plant with:

- Two 1960 kVA 34.5 kV - 4.16 kV transformers for the Wilson Gate service,
- 4.16 kV metal-clad generator and campus distribution switchgear,
- Plant 480/277-volt unit substation,
- Plant 480-volt motor control centers,
- Plant and substation medium and low voltage conduits and cables,
- One 4200 kVA 13.2 kV - 4.16 kV transformer for the Delafield Substation tie circuit, and
- Upgrade the tie circuit between Substation "B" and the Delafield Substation.

Construction of a new central plant will require substantially less electrical system capacity at the old power plant; the equipment will be removed. A portion of the old plant should be developed as the location for the central campus distribution switchgear, even if the remainder of the plant is developed for other uses.

Adding coal and ash handling systems, larger boiler fans, and pollution control equipment to the new plant will require additional motor control centers and a unit substation beyond those required for a gas/oil-fired plant.

Locating a new plant on any of the proposed plant sites will require installing a new tie circuit between the new plant and the Delafield Substation:

- Two new breakers in the Delafield Substation metal-enclosed switchgear, and
- 15 kV cables and concrete-encased duct bank and cable vaults.

Plan 5 - Hot Water Heat - New Central Gas/Oil-Fired Plant

Refer to Figure 9 for the schematic diagram for Plan 5. This plan consists of a new central plant producing high temperature hot water with gas/oil-fired boilers. Four sites as shown in Figure 1, were considered for this plan. All factors associated with site development, including adding sewers, water supply, access roads, power and visibility are considered. Natural gas for the boilers is assumed to be supplied by Central Hudson Gas and Electric Co. If gas from an independent supplier is used, it will also be transported through Central Hudson gas mains. No. 2 fuel oil will be the backup fuel.

A new distribution system to provide high temperature hot water to all buildings currently supplied with steam is included. Each building currently served by the existing central steam plant will be equipped with new converters to convert high temperature hot water to low temperature hot water or low pressure (LP) steam as required. The existing Laundry heating plant and buildings connected to the plant's distribution system will be connected to the new plant.

Three 125 MBtu/h hot water generators producing high temperature water at 400 °F are included. These generators will be gas or oil fired. SCR equipment is included to control nitrogen oxides emissions.

The options for providing chilled water to the campus include:

- Convert the existing absorption chillers to use hot water instead of steam or use steam generated in the convertors; new buildings will have centrifugal chillers (Option A),
- New central centrifugal chiller plant (Option C), and
- Replace all existing absorption chillers with centrifugal type chillers and use centrifugal chillers for all new buildings (Option D).

If a new central chilled water plant is used, it will be included as part of the boiler plant, and a chilled water distribution system will be installed to buildings with chilled water systems.

A separate incinerator plant to burn solid waste and generate hot water can be included with this plan as an option. The feasibility and costs of this option are discussed by Griggs (May 1994).

As part of the power plant replacement, the plant electrical distribution system should be replaced. It is approaching the end of its useful service life. Long-term reliability of the electrical distribution system requires installing new equipment. Replace Substation "B" and the electrical distribution equipment at the central plant with:

- Two 1960 kVA 34.5 kV - 4.16 kV transformers for the Wilson Gate service,
- 4.16 kV metal-clad generator and campus distribution switchgear,
- Plant 480/277-volt unit substation,
- Plant 480-volt motor control centers,
- Plant and substation medium and low voltage conduits and cables,
- One 4200 kVA 13.2 kV - 4.16 kV transformer for the Delafield Substation tie circuit, and
- Upgrade the tie circuit between Substation "B" and the Delafield Substation.

Constructing a new central plant will require substantially less electrical system capacity at the old power plant; the equipment will be removed. A portion of the old plant should be developed as the location for the central campus distribution switchgear, even if the remainder of the plant is developed for other uses.

Locating a new plant on any of the proposed plant sites will require installing a new tie circuit between the new plant and the Delafield Substation:

- Two new breakers in the Delafield Substation metal-enclosed switchgear, and
- 15 kV cables and concrete-encased duct bank and cable vaults.

Plan 6 - Hot Water Heat - New Central Coal-Fired Plant

Refer to Figure 10 for the schematic diagram for Plan 6. Four sites, as shown in Figure 1, were considered. Factors associated with site development, including adding sewer systems, water supply, access roads, power, and visibility are included in this plan.

A new distribution system to provide high temperature hot water to all buildings currently supplied with steam is included. Each building currently served by the existing central steam plant will be equipped with new converters to convert high temperature hot water to low temperature hot water or LP steam as required. The existing Laundry heating plant and buildings connected to the plant's distribution system will be connected to the new plant.

The options for providing chilled water to the campus include:

- Convert the existing absorption chillers to use hot water instead of steam or use steam generated in the convertors; new buildings will have centrifugal chillers (Option A),
- New central centrifugal chiller plant (Option C), and
- Replace all existing absorption chillers with centrifugal type chillers and use centrifugal chillers for all new buildings (Option D).

If a new central chilled water plant is used, it will be included as part of the boiler plant, and a chilled water distribution system will be installed to buildings with chilled water systems.

The new coal-fired plant includes three 125 MBtu/h stoker-fired hot water generators producing 400 °F water. A spray dry scrubber for control of sulfur dioxide emissions and a baghouse for control of particulate emissions are required. In addition, new coal storage and handling equipment, ash storage and handling equipment, lime storage and handling equipment, and a coal pile run-off collection and treatment facility will be required for this option.

A separate incinerator plant to burn solid waste and generate steam can be included with this plan as an option. The feasibility and costs of this option are discussed by Griggs (May 1994).

As part of the power plant replacement, the plant electrical distribution system should be replaced. It is approaching the end of its useful service life. Long-term reliability of the electrical distribution system requires installing new equipment. Replace Substation "B" and the electrical distribution equipment at the central plant with:

- Two 1960 kVA 34.5 kV - 4.16 kV transformers for the Wilson Gate service,
- 4.16 kV metal-clad generator and campus distribution switchgear,
- Plant 480/277-volt unit substation,
- Plant 480-volt motor control centers,
- Plant and substation medium and low voltage conduits and cables,
- One 4200 kVA 13.2 kV - 4.16 kV transformer for the Delafield Substation tie circuit, and
- Upgrade the tie circuit between Substation "B" and the Delafield Substation.

Constructing a new central plant will require substantially less electrical system capacity at the old power plant; the equipment will be removed. A portion of the old plant should be developed as the location for the central campus distribution switchgear, even if the remainder of the plant is developed for other uses.

Adding coal and ash handling systems, larger boiler fans, and pollution control equipment will require additional motor control centers and a unit substation beyond those required for a gas/oil-fired plant.

Locating a new plant on any of the proposed plant sites will require installing a new tie circuit between the new plant and the Delafield Substation:

- Two new breakers in the Delafield Substation metal-enclosed switchgear, and
- 15 kV cables and concrete-encased duct bank and cable vaults.

Plan 9 - New Cogeneration, Steam Topping Cycle, New Gas/Oil-Fired Central Steam Plant

Refer to Figure 11 for the schematic diagram for Plan 9. The new plant will be located at one of four potential sites as shown in Figure 1. Included for each of the four sites are factors associated with site development including adding sewers, water supply, access roads, power, and visibility from the remainder of the campus. Natural gas for the boilers is assumed to be supplied by Central Hudson Gas and Electric Co. If gas from an independent supplier is used, it will also be transported through Central Hudson gas mains. No. 2 fuel oil will be the backup fuel.

Two alternatives for steam distribution and condensate collection were considered. One is to use the existing steam distribution and condensate return systems with new piping as required to connect to the new plant. The second alternative is to replace the entire steam distribution and condensate return systems. The Laundry heating plant and its distribution system will be connected to the new plant distribution system.

The options for providing chilled water to the campus include:

- Use the existing (both absorption and centrifugal) chillers and use absorption chillers for all new buildings (Option A),
- New central absorption chiller plant (Option B), and
- Replace all existing centrifugal chillers with absorption type chillers and use absorption chillers for all new buildings (Option E).

If a new central chilled water plant is used, it will be included as part of the boiler plant, and a chilled water distribution system will be installed to buildings with chilled water systems.

This plan includes installing three new 125,000 lb/h gas/oil-fired boilers that generate steam at 600 psig and 750 °F. SCR equipment is included to control nitrogen oxide emissions. Oil storage and handling facilities will be required.

Two new 4000 kW, single automatic extraction/condensing turbine/generators equipped with auto extraction at 100 psig and condensing at 3 in. Hg (mercury) will also be installed. Throttle steam will be supplied at 600 psig and 750 °F. Cooling towers are included to provide condensing water.

A separate incinerator plant to burn solid waste and generate steam can be included with this plan as an option. The feasibility and costs of this option are discussed by Griggs (May 1994).

As part of the power plant replacement, the plant electrical distribution system should be replaced. It is approaching the end of its useful service life. Long-term reliability of the electrical distribution system requires installing new equipment. Replace Substation "B" and the electrical distribution equipment at the central plant with:

- Two 1960 kVA 34.5 kV - 4.16 kV transformers for the Wilson Gate service,
- 4.16 kV metal-clad generator and campus distribution switchgear,
- Plant 480/277-volt unit substation,
- Plant 480-volt motor control centers,
- Plant and substation medium and low voltage conduits and cables,
- One 4200 kVA 13.2 kV - 4.16 kV transformer for the Delafield Substation tie circuit, and
- Upgrade the tie circuit between Substation "B" and the Delafield Substation.

Constructing a new central plant will require substantially less electrical system capacity at the old power plant; the equipment will be removed. A portion of the old plant should be developed as the location for the central campus distribution switchgear, even if the remainder of the plant is developed for other uses.

Locating a new plant on any of the proposed plant sites will require installing a new tie circuit between the new plant and the Delafield Substation:

- Two new breakers in the Delafield Substation metal-enclosed switchgear, and
- 15 kV cables and concrete-encased duct bank and cable vaults.

The provision for generation in this plan will require the installation of generator breakers on the 13.2 kV bus.

Plan 10 - New Cogeneration, Steam Topping Cycle, New Coal-Fired Central Steam Plant

Refer to Figure 12 for the schematic diagram for Plan 10. Four sites, as shown in Figure 1, were considered for this plan. Factors associated with site development, including adding sewers, water supply, access roads, power, and visibility are also considered.

Two alternatives for steam distribution and condensate collection were considered. One is to use the existing steam distribution and condensate return systems with new piping as required to connect to the new plant. The second alternative is to replace the entire steam distribution and condensate return systems. The Laundry heating plant and its distribution system will be connected to the new plant distribution system.

The options for providing chilled water to the campus include:

- Use the existing (both absorption and centrifugal) chillers and use absorption chillers for all new buildings (Option A),
- New central absorption chiller plant (Option B), and
- Replace all existing centrifugal chillers with absorption type chillers and use absorption chillers for all new buildings (Option E).

If a new central chilled water plant is used, it will be included as part of the boiler plant, and a chilled water distribution system will be installed to buildings with chilled water systems.

This coal-fired plan includes three 125,000 lb/h boilers generating steam at 600 psig and 750 °F. The coal-fired plant will consist of either FBC units or stoker-fired boilers. With the FBC, only a baghouse is required for particulate emissions control. For the stoker-fired boiler, both a spray dry scrubber for control of sulfur dioxide emissions and a baghouse for control of particulate emissions are required.

Coal storage and handling equipment, ash storage and handling equipment, and lime or limestone storage and handling equipment are also required. For either the FBC or stoker-fired options, a new coal pile run-off collection and treatment system will be required.

Two new 4000 kW, single automatic extraction/condensing turbine/generators equipped with auto extraction at 100 psig and condensing at 3 in. Hg will also be installed. Throttle steam will be supplied at 600 psig and 750 °F. Cooling towers are included to provide condensing water.

A separate incinerator plant to burn solid waste and generate steam can be included with this plan as an option. The feasibility and costs of this option are discussed by Griggs (May 1994).

As part of the power plant replacement, the plant electrical distribution system should be replaced. It is approaching the end of its useful service life. Long-term reliability of the electrical distribution system requires installing new equipment. Replace Substation "B" and the electrical distribution equipment at the central plant with:

- Two 1960 kVA 34.5 kV - 4.16 kV transformers for the Wilson Gate service,
- 4.16 kV metal-clad generator and campus distribution switchgear,
- Plant 480/277-volt unit substation,
- Plant 480-volt motor control centers,
- Plant and substation medium and low voltage conduits and cables,
- Plant and substation medium and low voltage conduits and cables,
- One 4200 kVA 13.2 kV - 4.16 kV transformer for the Delafield Substation tie circuit, and
- Upgrade the tie circuit between Substation "B" and the Delafield Substation.

Constructing a new central plant will require substantially less electrical system capacity at the old power plant; the equipment will be removed. A portion of the old plant should be developed as the location for the central campus distribution switchgear, even if the remainder of the plant is developed for other uses.

Adding coal and ash handling systems, large boiler fans, and pollution control equipment will require additional motor control centers and a unit substation beyond those required for a gas/oil-fired plant.

Locating this new plant on any of the proposed plant sites will require the installation of a new tie circuit between the new plant and the Delafield Substation:

- Two new breakers in the Delafield Substation metal-enclosed switchgear, and
- 15 kV cables and concrete-encased duct bank and cable vaults.

The provision for generation in this plan will require the installation of generator breakers on the 13.2 kV bus.

Plan 11 - New Cogeneration - Simple Cycle Gas Turbine

Refer to Figure 13 for the schematic diagram and Figure 14 for the general arrangement drawing. The new plant will be located at one of four potential sites as shown in Figure 1. Included for each of the four sites are factors associated with site development including adding sewers, water supply, access roads, power, and visibility from the remainder of the campus. Natural gas for the boilers is assumed to be supplied by Central Hudson Gas and Electric Co. If gas from an independent supplier is used, it will also be transported through Central Hudson gas mains. No. 2 fuel oil will be the backup fuel.

Two alternatives for steam distribution and condensate collection were considered. One is to use the existing steam distribution and condensate return systems with new piping as required to connect to the new plant. The second alternative is to replace the entire steam distribution and condensate return systems. The Laundry heating plant and its distribution system will be connected to the new plant distribution system.

The options for providing chilled water to the campus include:

- Use the existing (both absorption and centrifugal) chillers and use absorption chillers for all new buildings (Option A),
- New central absorption chiller plant (Option B), and.
- Replace all existing centrifugal chillers with absorption type chillers and use absorption chillers for all new buildings (Option E).

If a new central chilled water plant is used, it will be included as part of the boiler plant, and a chilled water distribution system will be installed to buildings with chilled water systems.

This plan includes installing two new 3925 kW Allison 501 KB5 gas turbine/generators, two 80,000 lb/h waste heat boilers, each with supplemental gas/oil-firing, and two 80,000 lb/h gas/oil-fired boilers. Steam from all boilers will be produced at 100 psig, 400 °F. The two waste heat boilers can each generate 23,000 lb/h steam in the unfired mode plus an additional 57,000 lb/h steam with supplemental firing. SCR equipment is included on all boiler and turbine exhausts to control emissions of nitrogen oxides. Oil storage and handling facilities are required.

A separate incinerator plant to burn solid waste and generate steam can be included with this plan as an option. The feasibility and costs of this option are discussed by Griggs (May 1994).

As part of the power plant replacement, the plant electrical distribution system should be replaced. It is approaching the end of its useful service life. Long-term reliability of the electrical distribution system requires installing new equipment. Replace Substation "B" and the electrical distribution equipment at the central plant with:

- Two 1960 kVA 34.5 kV - 4.16 kV transformers for the Wilson Gate service,
- 4.16 kV metal-clad generator and campus distribution switchgear,
- Plant 480/277-volt unit substation,
- Plant 480-volt motor control centers,
- Plant and substation medium and low voltage conduits and cables,
- One 4200 kVA 13.2 kV - 4.16 kV transformer for the Delafield Substation tie circuit, and
- Upgrade the tie circuit between Substation "B" and the Delafield Substation.

Constructing a new central plant will require substantially less electrical system capacity at the old power plant; the equipment will be removed. A portion of the old plant should be developed as the

location for the central campus distribution switchgear, even if the remainder of the plant is developed for other uses.

Locating a new plant on any of the proposed plant sites will require installing a new tie circuit between the new plant and the Delafield Substation:

- Two new breakers in the Delafield Substation metal-enclosed switchgear, and
- 15 kV cables and concrete-encased duct bank and cable vaults.

The provision for generation in this plan will require the installation of generator breakers on the 13.2 kV bus.

Plan 12 - New Cogeneration - Combined Cycle Gas Turbine

Refer to Figure 15 for the schematic diagram and Figure 16 for the general arrangement drawing. The new plant is to be located at one of four potential sites as shown in Figure 1. Included for each of the four sites are factors associated with site development including adding sewers, water supply, access roads, power, and visibility from the remainder of the campus. Natural gas for the boilers is assumed to be supplied by Central Hudson Gas and Electric Co. If gas from an independent supplier is used, it will also be transported through Central Hudson gas mains. No. 2 fuel oil will be the backup fuel.

Two alternatives for steam distribution and condensate collection were considered. One is to use the existing steam distribution and condensate return systems with new piping as required to connect to the new plant. The second alternative is to replace the entire steam distribution and condensate return systems. The Laundry heating plant and its distribution system will be connected to the new plant distribution system.

The options for providing chilled water to the campus include:

- Use the existing (both absorption and centrifugal) chillers and use absorption chillers for all new buildings (Option A),
- New central absorption chiller plant (Option B), and
- Replace all existing centrifugal chillers with absorption type chillers and use absorption chillers for all new buildings (Option E).

If a new central chilled water plant is used, it will be included as part of the boiler plant, and a chilled water distribution system will be installed to buildings with chilled water systems.

This plan includes installing one new 5588 kW Allison 571K gas turbine/generator, one 80,000 lb/h waste heat boiler with supplemental gas/oil-firing, and three 80,000 lb/h boilers producing steam at 100 psig, 400 °F. The waste heat boiler can generate 21,100 lb/h steam in the unfired mode plus an additional 58,900 lb/h steam with supplemental firing at 600 psig, 750 °F. Also included is one 2000 kW backpressure turbine generator exhausting at 100 psig with throttle steam at 600 psig, 750 °F. SCR equipment is included on all boiler and turbine exhausts to control emissions of nitrogen oxides. Oil storage and handling facilities are required.

A separate incinerator plant to burn solid waste and generate steam can be included with this plan as an option. The feasibility and costs of this option are discussed by Griggs (May 1994).

As part of the power plant replacement, the plant electrical distribution system should be replaced. It is approaching the end of its useful service life. Long-term reliability of the electrical distribution

system requires installing new equipment. Replace Substation "B" and the electrical distribution equipment at the central plant with:

- Two 1960 kVA 34.5 kV - 4.16 kV transformers for the Wilson Gate service,
- 4.16 kV metal-clad generator and campus distribution switchgear,
- Plant 480/277-volt unit substation,
- Plant 480-volt motor control centers,
- Plant and substation medium and low voltage conduits and cables,
- One 4200 kVA 13.2 kV - 4.16 kV transformer for the Delafield Substation tie circuit, and
- Upgrade the tie circuit between Substation "B" and the Delafield Substation.

Constructing a new central plant will require substantially less electrical system capacity at the old power plant; the equipment will be removed. A portion of the old plant should be developed as the location for the central campus distribution switchgear, even if the remainder of the plant is developed for other uses.

Locating a new plant on any of the proposed plant sites will require installing a new tie circuit n between the new plant and the Delafield Substation:

- Two new breakers in the Delafield Substation metal-enclosed switchgear, and
- 15 kV cables and concrete-encased duct bank and cable vaults.

The provision for generation in this plan will require the installation of generator breakers on the 13.2 kV bus.

Plan 13 - New Cogeneration - Diesel Engines, Gas/Oil-Fired

Refer to Figure 17 for the schematic diagram and Figure 18 for the general arrangement drawing. The new plant will be located at one of four potential sites as shown in Figure 1. Included for each of the four sites are factors associated with site development including adding sewers, water supply, access roads, power, and visibility from the remainder of the campus. Natural gas is assumed to be supplied by Central Hudson Gas and Electric Co. If gas from an independent supplier is used, it will also be transported through Central Hudson gas mains. No. 2 fuel oil will be the backup fuel for the boilers and the pilot fuel for the diesel engines.

Two alternatives for steam distribution and condensate collection were considered. One is to use the existing steam distribution and condensate return systems with new piping as required to connect to the new plant. The second alternative is to replace the entire steam distribution and condensate return systems. The Laundry heating plant and its distribution system will be connected to the new plant distribution system.

The options for providing chilled water to the campus include:

- Use the existing (both absorption and centrifugal) chillers and use absorption chillers for all new buildings (Option A),
- New central absorption chiller plant (Option B), and
- Replace all existing centrifugal chillers with absorption type chillers and use absorption chillers for all new buildings (Option E).

If a new central chilled water plant is used, it will be included as part of the boiler plant, and a chilled water distribution system will be installed to buildings with chilled water systems.

This plan includes installing two new 3750 kW Cooper LSVB-12-GDT dual fuel engines (95 percent gas, 5 percent No. 2 fuel oil), operating at 400 rpm. Catalytic controls for engine nitrogen oxides emissions are included. Two hot water heat exchangers, one per engine, are included to recover engine jacket water heat for preheating makeup water.

This plan also includes two 24,000 lb/h waste heat boilers with provisions for supplemental gas/oil-firing. Each waste heat boiler can produce 9300 lb/h steam in the unfired mode and an additional 14,700 lb/h steam with supplemental firing. Steam is produced at 100 psig, 400 °F. Three new 80,000 lb/h gas/oil-fired boilers will also be installed and will also produce steam at 100 psig, 400 °F. SCR equipment is included on all engine and boiler exhausts to control nitrogen oxide emissions. Oil storage and handling facilities will be required.

A separate incinerator plant to burn solid waste and generate steam can be included with this plan as an option. The feasibility and costs of this option are discussed by Griggs (May 1994).

As part of the power plant replacement, the plant electrical distribution system should be replaced. It is approaching the end of its useful service life. Long-term reliability of the electrical distribution system requires installing new equipment. Replace Substation "B" and the electrical distribution equipment at the central plant with:

- Two 1960 kVA 34.5 kV - 4.16 kV transformers for the Wilson Gate service,
- 4.16 kV metal-clad generator and campus distribution switchgear,
- Plant 480/277-volt unit substation,
- Plant 480-volt motor control centers,
- Plant and substation medium and low voltage conduits and cables,
- One 4200 kVA 13.2 kV - 4.16 kV transformer for the Delafield Substation tie circuit, and
- Upgrade the tie circuit between Substation "B" and the Delafield Substation.

Constructing a new central plant will require substantially less electrical system capacity at the old power plant; the equipment will be removed. A portion of the old plant should be developed as the location for the central campus distribution switchgear, even if the remainder of the plant is developed for other uses.

Locating a new plant on any of the proposed plant sites will require installing a new tie circuit between the new plant and the Delafield Substation:

- Two new breakers in the Delafield Substation metal-enclosed switchgear, and
- 15 kV cables and concrete-encased duct bank and cable vaults.

The provision for generation in this plan will require the installation of generator breakers on the 13.2 kV bus.

Plan 14 - New Cogeneration - Large Simple Cycle Gas Turbine, Third-Party Financed

Refer to Figure 19 for the schematic diagram for Plan 14. The new plant will be located at Site 1 or Site 4 as shown in Figure 1. Included for these two sites are all factors associated with site development including adding sewers, water supply, access roads, power, and visibility from the remainder of the campus. Natural gas for the boilers is assumed to be supplied by Central Hudson Gas and Electric Co. If gas from an independent supplier is used, it will also be transported through Central Hudson gas mains. No. 2 fuel oil will be the backup fuel.

Two alternatives for steam distribution and condensate collection were considered. One is to use the existing steam distribution and condensate return systems with new piping as required to connect to the new plant. The second alternative is to replace the entire steam distribution and condensate return systems. The Laundry heating plant and its distribution system will be connected to the new plant distribution system.

The options for providing chilled water to the campus include:

- Use the existing (both absorption and centrifugal) chillers and use absorption chillers for all new buildings (Option A),
- New central absorption chiller plant (Option B), and
- Replace all existing centrifugal chillers with absorption type chillers and use absorption chillers for all new buildings (Option E).

If a new central chilled water plant is used, it will be included as part of the boiler plant, and a chilled water distribution system will be installed to buildings with chilled water systems.

This plan includes installing one new 32,500 kW GE LM 5000 gas turbine/generator with steam injection, one 225,000 lb/h waste heat boiler with supplemental gas/oil-firing, and two 125,000 lb/h gas/oil-fired heating boilers. Steam from the heating boilers will be produced at 100 psig, 400 °F. Steam from the waste heat boiler will be produced at 495 psig, 550 °F, and reduced to 100 psig, 400 °F for distribution. The waste heat boiler can generate 120,000 lb/h steam in the unfired mode plus an additional 105,000 lb/h steam with supplemental firing.

The gas turbine generator electrical output can be increased by using steam injection into the gas turbine at 495 psig, 550 °F. With 30,200 lb/h steam injection, output is increased to 37,000 kW; with 80,000 lb/h steam injection, output is increased to 45,150 kW for summer peak loads. Only steam not otherwise needed by the USMA will be used for injection.

All electric power produced will be sold to the local power company. Steam and chilled water produced at this facility will be sold to the USMA.

SCR equipment is included on all boiler and turbine exhausts to control emission of nitrogen oxides. Oil storage and handling facilities will be required.

A separate incinerator plant to burn solid waste and generate steam can be included with this plan as an option. The feasibility and costs of this option are discussed by Griggs (May 1994).

As part of the power plant replacement, the plant electrical distribution system should be replaced. It is approaching the end of its useful service life. Long-term reliability of the electrical distribution system requires installing new equipment. Replace Substation "B" and the electrical distribution equipment at the central plant with:

- Two 1960 kVA 34.5 kV - 4.16 kV transformers for the Wilson Gate service,
- 4.16 kV metal-clad generator and campus distribution switchgear,
- Plant 480/277-volt unit substation,
- Plant 480-volt motor control centers,
- Plant and substation medium and low voltage conduits and cables,
- One 4200 kVA 13.2 kV - 4.16 kV transformer for the Delafield Substation tie circuit, and
- Upgrade the tie circuit between Substation "B" and the Delafield Substation.

Constructing a new central plant will require substantially less electrical system capacity at the old power plant; the equipment will be removed. A portion of the old plant should be developed as the location for the central campus distribution switchgear, even if the remainder of the plant is developed for other uses.

Locating a new plant on any of the proposed plant sites will require installing a new tie circuit between the new plant and the Delafield Substation:

- Two new breakers in the Delafield Substation metal-enclosed switchgear, and
- 15 kV cables and concrete-encased duct bank and cable vaults.

The provision for generation in this plan will require the installation of generator breakers on the 13.2 kV bus.

In addition, the utility will be required to implement a substantial upgrade of the high voltage side of the Delafield Substation, including the feeders serving the substation, in order to transmit the power generated to the utility company. Costs of this upgrade are not included in this study.

Plan 15 - New Cogeneration - Large Combined Cycle Gas Turbine, Third-Party Financed

Refer to Figure 20 for the schematic diagram for Plan 15. The new plant will be located at Site 1 or Site 4 as shown in Figure 1. Included for these two sites are factors associated with site development including adding sewers, water supply, access roads, power, and visibility from the remainder of the campus. Natural gas for the boilers is assumed to be supplied by Central Hudson Gas and Electric Co. If gas from an independent supplier is used, it will also be transported through Central Hudson gas mains. No. 2 fuel oil will be the backup fuel.

Two alternatives for steam distribution and condensate collection were considered. One is to use the existing steam distribution and condensate return systems with new piping as required to connect to the new plant. The second alternative is to replace the entire steam distribution and condensate return systems. The Laundry heating plant and its distribution system will be connected to the new plant distribution system.

The options for providing chilled water to the campus include:

- Use the existing (both absorption and centrifugal) chillers and use absorption chillers for all new buildings (Option A),
- New central absorption chiller plant (Option B), and
- Replace all existing centrifugal chillers with absorption type chillers and use absorption chillers for all new buildings (Option E),

If a new central chilled water plant is used, it will be included as part of the boiler plant, and a chilled water distribution system will be installed to buildings with chilled water systems.

This plan includes installing two new 21,000 kW GE LM 2500 gas turbine/generators with steam injection, two 120,000 lb/h waste heat boilers each with supplemental gas/oil-firing, and one 125,000 lb/h gas/oil-fired heating boiler. Steam from the heating boiler will be produced at 100 psig, 400 °F.

The two dual pressure waste heat boilers can each generate 70,000 lb/h steam in the unfired mode, plus an additional 30,000 lb/h steam with supplemental firing at 600 psig, 750 °F. These boilers can

simultaneously produce 20,000 lb/h each of 100 psig, 400 °F steam in either the fired or unfired mode of operation using a second steam generating section.

Also included is one new 10,000 kW auto extraction condensing steam turbine generator with auto extraction at 100 psig and condensing at 3 in. Hg. Throttle steam is supplied at 600 psig, 750 °F. A cooling tower is also included.

With steam injection into the gas turbines, the electrical output can be increased. With steam injection at a rate of 19,500 lb/hr, output is increased to 23,600 kW, and with steam injection at a rate of 40,000 lb/hr, output is increased to 26,200 kW for each gas turbine. Only steam not otherwise needed by the USMA will be used for injection.

All electric power produced will be sold to the local power company. Steam and chilled water produced at this facility will be sold to the USMA.

SCR equipment is included on all boiler and turbine exhausts to control emission of nitrogen oxides. Oil storage and handling facilities will be required.

A separate incinerator plant to burn solid waste and generate steam can be included with this plan as an option. The feasibility and costs of this option are discussed by Griggs (May 1994).

As part of the power plant replacement, the plant electrical distribution system should be replaced. It is approaching the end of its useful service life. Long-term reliability of the electrical distribution system requires installing new equipment. Replace Substation "B" and the electrical distribution equipment at the central plant with:

- Two 1960 kVA 34.5 kV - 4.16 kV transformers for the Wilson Gate service,
- 4.16 kV metal-clad generator and campus distribution switchgear,
- Plant 480/277-volt unit substation,
- Plant 480-volt motor control centers,
- Plant and substation medium and low voltage conduits and cables,
- One 4200 kVA 13.2 kV - 4.16 kV transformer for the Delafield Substation tie circuit, and
- Upgrade the tie circuit between Substation "B" and the Delafield Substation.

Constructing a new central plant will require substantially less electrical system capacity at the old power plant; the equipment will be removed. A portion of the old plant should be developed as the location for the central campus distribution switchgear, even if the remainder of the plant is developed for other uses.

Locating a new plant on any of the proposed plant sites will require installing a new tie circuit between the new plant and the Delafield Substation:

- Two new breakers in the Delafield Substation metal-enclosed switchgear, and
- 15 kV cables and concrete-encased duct bank and cable vaults.

The provision for generation in this plan will require the installation of generator breakers on the 13.2 kV bus.

In addition, the utility will be required to implement a substantial upgrade of the high voltage side of the Delafield Substation, including the feeders serving the substation, in order to transmit the power generated to the utility company. Costs of this upgrade are not included in this study.

Plan 16 - All Electric Energy

The existing power plant and steam distribution system will be shut down and removed. The existing electrical distribution system will be expanded to provide all electric service, including heating, to each building. All existing absorption chillers will be replaced by motor-driven centrifugal or reciprocating chillers.

As part of the power plant replacement, the plant electrical distribution system should be replaced. It is approaching the end of its useful service life. Long-term reliability of the electrical distribution system requires installing new equipment. Replace Substation "B" and the electrical distribution equipment at the central plant with:

- Two 1960 kVA 34.5 kV - 4.16 kV transformers for the Wilson Gate service,
- 4.16 kV metal-clad generator and campus distribution switchgear,
- Plant 480/277-volt unit substation,
- Plant 480-volt motor control centers,
- Plant and substation medium and low voltage conduits and cables,
- One 4200 kVA 13.2 kV - 4.16 kV transformer for the Delafield Substation tie circuit, and
- Upgrade the tie circuit between Substation "B" and the Delafield Substation.

This plan will require substantial replacement of the campus electrical distribution system to serve the new electric heating loads. The replacement of transformers, feeders, and switchgear would be as follows:

- Fifty 1500 kVA pad-mounted transformers,
- Fifty service entrance switchboards,
- Fifty pad-mounted switches,
- 30,000 feet of duct bank and 15 kV cables, and
- Replacement of the Delafield Substation switchgear.

In addition, the utility will be required to implement a substantial upgrade of the high voltage side of the Delafield Substation, including the feeders serving the substation. Costs of this are not included in this study.

Plan 17 - Geothermal Energy

This technology uses naturally occurring heat energy obtained from below the surface of the earth to provide heat, chilled water, and electrical energy.

Electricity is produced from geothermal resources by converting part of the thermal energy (heat) into mechanical energy, which is then used to generate electricity. Geothermal energy sources are classified as hydrothermal, geopressurized, or petrothermal.

Hydrothermal energy systems are those in which subterranean water is heated by direct contact with hot rock structures deep within the earth. Fissures, or vents, through the rock cap covering the heated water resource allows this water to escape to the surface as either steam or hot water. Hydrothermal systems are subdivided into vapor-dominated and liquid-dominated systems.

In vapor-dominated systems, the subterranean water is vaporized into steam, which reaches the surface in a relatively dry condition at about 400 °F and 100 psig. This steam is suitable for use in steam turbine/electric generator power plants. The primary disadvantage of vapor-dominated systems, and all

other geothermal energy sources, is the presence of corrosive gases and erosive materials carried with the steam. Vapor-dominated systems are a rarity with only five known sites worldwide.

Liquid-dominated systems are those in which the subterranean water exists at a temperature between 350 and 600 °F. When this type of aquifer is tapped by wells, the water will flow to the surface, if sufficient pressure is available, or it can be pumped to the surface. In either case, the reduction in pressure, as the hot water moves to the surface, results in a final steam pressure of about 100 psig. This drop in pressure causes part of the hot water to flash to steam and results in a low-quality, two-phase mixture; a liquid-dominated mixture. This mixture contains high concentrations of dissolved solids that tend to precipitate and cause scaling in pipes and on heat exchanger surfaces. Liquid-dominated systems are, however, the most common type of hydrothermal energy recovery in use today.

Geopressurized energy systems are those in which the subterranean water has been heated in the same manner as hydrothermal water, but tends to be at a lower temperature (thought to be about 325 °F) and extremely high pressure, perhaps 15,000 psia, or more. The high pressure is due to the 8000 to 30,000 ft of overlying formations that entrap the water. This water (actually brine containing 4 to 10 percent salinity) is saturated with natural gas.

Although geopressurized water is expected to have sufficient thermal and mechanical potential to generate electricity, its low temperature and great depth make it uneconomical to recover for its thermal energy alone. However, geopressurized water may contain sufficient quantities of natural gas (primarily methane) to justify recovery and use of both the natural gas and thermal energy of the water in a combined cycle cogeneration facility. About 20 prospective geopressurized sites have been identified in the United States. All are located along the gulf coasts of Texas and Louisiana. This technology requires much development work before it is considered suitable for commercial applications.

Petrothermal energy systems are simply hot, dry rock formations located below the earth's surface. The temperature of these formations is known to be in the range of 300 to 550 °F. Petrothermal energy represents about 85 percent of the total geothermal energy base of the United States, according to some estimates. Other estimates give the ratio of steam to hot water to hot dry rocks as 1:10:1000.

Most of the hot dry rock formations considered for energy recovery are located at moderate depths, but the formations are largely impermeable. To extract heat from these formations, water would be pumped into them and then back to the surface. For this to be an effective heat recovery method, it is necessary to fracture the rock structures to increase the heat transfer surface; a large surface area is necessary due to the low thermal conductivity of the rock. Both high pressure water and nuclear explosives are under consideration as the means of creating the necessary fractures in these rock formations.

Fracturing these formations using high pressure water is an untried method in the hard rock formations, although it has been successfully used by the petroleum industry in soft, sedimentary rock formations. The use of nuclear explosives may be economically effective but poses significant environmental hazards including ground shocks, possible radioactive releases to the environment, as well as radioactive material brought to the surface with the steam and hot water.

These geothermal energy systems are not currently applicable for the USMA since no known geothermal energy source is relatively close to the earth's surface in this area.

Plan 18 - Solar Thermal Electric Power

The sun's energy is free, inexhaustible, and involves no transportation constraints. Pollutants other than waste heat, are insignificant. However, radiant energy from the sun is diffuse and a large reflector surface area is required to generate electrical energy. The Point Focus Central Receiver System (or the power tower concept) coupled to a Rankine cycle heat engine ranks high in technical, economic, and institutional feasibility. The steam-Rankine cycle is a proven technology and the system is not sensitive to economies of scale. The Point Focus Central Receiver System is best suited for daytime peaking and fossil fuel saving operations. It currently has a useful size range of 1 to 3 megawatts-electric (MWe), although installations of up to 400 MWe may be possible in the future.

Solar thermal electric power requires a large initial capital investment, and the cost of electricity depends on the site. Other problems relate to weather concerns, land requirements, component life, and long-term reliability.

The Army Energy Plan states that solar energy systems funded by the Department of Defense must be cost-effective using the sum of all capital and operating costs associated with the energy system over the life of the system, or 25 years, whichever is shorter and using marginal fuel costs at a discount rate of 7 percent per year.

All completed Army solar projects have been located south of 40° north latitude, primarily in the Texas-Louisiana area. Therefore, since the USMA is north of 40° north latitude, this plan currently is not considered to be either technically or economically appropriate for the USMA.

Plan 19 - Solar Photovoltaics

In a solar photovoltaic system, electricity is generated by solar cells made of silicon or other similar semiconductor material. The system consists of a flat-panel, fixed-angle array field of solar cell modules. Presently, this system is more advanced and more applicable to a wider geographic area than the concentrator-type system previously discussed as Plan 18.

The flat-panel system is best suited for daytime peaking operations and fossil fuel savings. Because the economies of scale associated with this technology are minimal, there is no minimum or maximum useful size for a photovoltaic system.

There are several major reasons for interest in this technology. Because the sun is the energy source, long-term fuel availability is not a concern, and there is significant siting flexibility. Reduced transmission-distribution line losses, costs, and land requirements are possible through dispersed siting. The modular design permits small incremental additions and reduces service lead times.

A primary difficulty is that the cost of electricity is site dependent. This restricts generation to areas where economic practicality is achievable. In addition, some siting constraints exist due to the large land area required. Other concerns include maintenance requirements, component life, long-term reliability, and storage during night hours and on cloudy days.

A 1-megawatt, two-axis tracking flat-panel photovoltaic installation was completed in California, demonstrating that the technology is currently available. However, the technology is not considered economically practical until costs are reduced (Huss, Richmond, and Badger 1984).

Plan 20 - Small-Scale Hydroelectric

Hydroelectric power generation involves producing electricity from generators driven by hydraulic turbines. In some areas of the United States, existing dams can be modified for small-scale electric generation. These existing dams offer the opportunity to install hydrogeneration at substantially reduced cost when compared to generation connected with new dam construction. Peaking, intermediate, or base-load operations are possible with hydroelectric generation. The useful range of these facilities is approximately 50 kW and larger, depending on the specific site.

Hydroelectric generation is highly efficient and uses a relatively simple design of a well-established technology. The technology is very reliable and has no air, solid waste, or thermal pollution effects. Small-scale hydroelectric generation has a long life when compared to conventional thermal generation and its cost is independent of escalating fossil fuel prices.

Hydroelectric generation, however, is not without problems. It generally is not practical if new dam costs are totally chargeable to electricity generation; therefore, siting is limited to existing dams or sites where impoundments have multiple purposes. Initial capital cost is high compared to conventional thermal generation. Downstream flow rates and changes in reservoir levels may adversely affect ecosystems and reduce recreational values and water supply reliability and may, therefore, be restricted by legislation (e.g., Glen Canyon Dam).

This technology is available, although it is economically practical only at existing dams of suitable head. No such dams were found on the Hudson River near West Point. Because it is unlikely that a hydroelectric dam and generating facility will be allowed to be built in this vicinity, this plan is not considered a feasible technology for the USMA.

Plan 21 - Wind Power

Wind power is a special application of solar energy since wind is created primarily by the unequal heating of the earth by the sun. The surface of oceans and lakes, and the air over them, remain relatively cool during the day since much of the sun's heat is either consumed in the evaporation of water or is absorbed by the large mass of water, which is able to absorb a great deal of heat with minimal temperature rise. Land surfaces, on the other hand, heat up considerably during the day. The land then warms the overlying air which expands, becoming lighter, and rises. The cooler and heavier air over the water moves in to replace it, creating a local breeze from water to shore. At night, the land and the air above it cool more rapidly than the water. This cool air then blows seaward to replace the warm air that rises from the surface of the water.

Useful energy can be extracted if a structure is able to move continuously under the influence of wind force. This energy can then be converted into electricity by suitable electromechanical interfacing. Extraction of wind energy can be accomplished by using horizontal axis or vertical axis wind turbines. Horizontal axis wind turbines are more advanced in their engineering design than vertical axis machines and are, therefore, of greater interest to energy planners. Wind turbines have a useful size range of 7.5 megawatts or smaller, but they can be grouped in wind farms. They are best suited for peaking and fuel saving operations.

Wind generation has minimum environmental impacts, limitless fuel with no direct cost, and a short lead time compared to conventional power plants. In addition, the concept of wind generation is simple enough to allow design standardization and, in turn, mass production, which reduces costs per unit.

Problems associated with wind generation are related to the unreliable nature of wind. This affects power availability and siting. In addition, large amounts of air are required to obtain a significant amount of usable energy. The cost of electricity from wind generation may be competitive only if units are mass produced.

The consensus reached in many studies financed by the U.S. Government suggests that wind energy should eventually become a practical energy option but that it is not economically feasible at this time. Therefore, wind power is not recommended for the USMA due to siting requirements and the known unreliability of wind in the area.

Plan 22 - Wood/Biomass

Wood or other biomass material can be used as a fuel to generate steam, which is then used to produce electric power by conventional technology. The most efficient method of using wood is direct combustion using a spreader-stoker feed to a boiler coupled to a conventional steam turbine system. This method is a near-term alternative to fossil fuels. Wood-fired steam plants are suitable for base-load operations and have a useful size range of up to 50 megawatts.

Wood is a renewable resource and a minimal emitter of sulfur dioxide. It is less expensive than oil or natural gas and can be competitive with coal in some geographic areas. However, wood may be difficult to obtain in some areas, and increased competition for waste wood supplies may cause an increase in price. It is bulky, difficult to handle, and has high transportation costs and large storage area requirements. Carbon monoxide and hydrocarbon emissions result if combustion is incomplete.

This technology is available and economically practical on a site-specific basis. Wood/biomass is not a recommended fuel alternative for the USMA due to limited local availability and high transportation costs.

Plan 23 - Fuel Cells

Fuel cell power plants convert the energy of a fuel directly to electricity by an electrochemical process, rather than by combustion. Because the same electrochemical reactions occur in each individual cell, power plant efficiency is nearly independent of the number of cells and plant size. The "phosphoric acid-type" fuel cell system is a first generation technology and is technically available. Second-generation fuel cell technology using molten carbonate as the electrolyte has advanced to the point of large-scale demonstration projects. A 100-kW test of a molten-carbonate design at Pacific Gas & Electric is scheduled for early 1991 (Smock 1990). Fuel cell systems are suitable for peaking or intermediate operations and have a useful range of up to ten megawatts.

High conversion efficiency in the range of 70 to 80 percent (Minkov et al. 1988) is projected for fuel cells and, because of their modular design, relatively small additions to capacity should be possible without loss of efficiency. High efficiencies are possible since fuel cells do not depend on the flow of heat between a thermal source and a sink as in a heat engine. Therefore, fuel cells are not subject to the thermodynamic Carnot limitations (Minkov et al. 1988).

The technology has environmental compatibility because nitrogen, sulfur oxides, and particulate emission levels are lower than any existing or projected requirements. In addition, water and land requirements are minimal and fuel cells may be sited in developed areas. Fuel flexibility is possible as long as hydrogen can be made as an intermediate step.

Problems are primarily related to costs of fabrication, operations, and maintenance of fuel cell stacks, and costs of the phosphoric acid fuel cell catalyst (platinum). Other concerns involve the use of scarce fuels (currently naphtha and natural gas) and the need for further developments to permit using cost-efficient, coal-derived fuels.

The use of fuel cells is not recommended for the USMA at this time due to the high cost of the technology and lack of commercial availability.

Plan 24 - Coal Gasification and Coal Liquefaction

The objective of this technology is to produce and use a clean-burning gas from coal. Coal gasification is more complex than direct-fired coal applications. One of the more advanced applications is in combined-cycle power generation. Coal gasification facilities are best suited for large base-load operations. No specific limits are placed on size ranges of these facilities.

<u>Coal Gasification-Combined Cycle</u>. Coal gasification provides an alternative way of using high-sulfur coal and avoids stack gas scrubbing by the end user. In addition, integrating a gasification plant with a combined-cycle power plant permits greater use of available heat so overall efficiency is comparable to that of a coal-fired plant.

<u>Coal Liquefaction</u>. The product of the solvent refined coal (SRC) process, or coal liquefaction, is low melting potential boiler fuel (SRC-1). The major objective of the SRC process is to produce an ashless, low-sulfur coal for use in power plants and other large industrial installations. Because the product of the SRC process is a fuel, not electricity, the technology defined here includes only the coal liquefaction process. The use of the product as a fuel to generate heat and electric power is not discussed.

SRC-1 is a fuel best suited for existing coal and residual fuel oil boilers. The need for flue gas scrubbing is eliminated and particulate emission control is simplified. However, coal liquefaction has high processing costs, large water requirements, and produces potentially toxic products. In addition, only relatively small pilot plants have been placed in operation.

As previously mentioned, coal gasification is best suited for large base-load operations while coal liquefaction (solvent refined coal) is best suited as a replacement fuel for existing coal and residual fuel oil fired boilers. Neither of these coal cleaning technologies is considered feasible for installations the size of the USMA. However, fuels from these technologies may be available to the USMA from commercial suppliers in future years as supplies of natural gas and fuel oil diminish.

Plan 25 - Ocean Thermal Energy Conversion (OTEC)

OTEC is a power generation system that uses the natural thermal gradient found in tropical water. A candidate site must have abundant warm surface water to provide the heat source and accessible cold water to serve as the heat sink for the engine to generate power. For continuous, efficient operation of an OTEC plant, an annual average temperature difference of 20 °C (36 °F) is needed. OTEC facilities are best suited for base-load operations and have a useful size range of 100 to 400 megawatts-electric.

Benefits of this technology include minimal air emissions, availability of a constant, renewable energy source, and high reliability. Additionally, the technology required for OTEC systems is well established.

Problems associated with OTEC technology center around siting and cost. No working commercial-scale demonstration plants have been installed to date. The nature and magnitude of environmental

impacts are uncertain, and the perceived risks of the technology may result in very high insurance costs. Therefore, OTEC is not considered applicable to the USMA.

Plan 26 - Magnetohydrodynamics (MHD)

MHD is a long-term energy alternative. Electricity is generated directly from thermal energy, thus eliminating the conversion step of thermal to mechanical energy in conventional steam-electric generators. A coal-fired, open-cycle system is presently thought to be the most promising for commercial application. The anticipated mode of operation for MHD systems is base-load operations, with a useful range of 500 to 1000 megawatts or greater.

This technology offers potential opportunities for low-cost, base-load electricity from an available energy source (coal) with anticipated high efficiency. The MHD generator will also be responsive to rapid load fluctuations.

Problems associated with MHD are numerous. High capital costs are anticipated, siting constraints will be a factor, and extensive improvements are required for some components. Environmental and safety problems are also likely, but no more so than for conventional coal-burning systems. Therefore, this technology is not expected to be technically or economically feasible until after the year 2000 and is not recommended for the USMA.

Plan 27 - Nuclear Energy

This technology uses nuclear fuel in a reactor to produce steam. The steam is used to drive a steam turbine electric generator and also serves as the source of thermal energy used for heating and production of chilled water.

This technology is both technically and economically feasible but only in large base-load plants. Equipment is neither commercially available nor economically feasible for facilities the size of the USMA and is, therefore, not recommended.

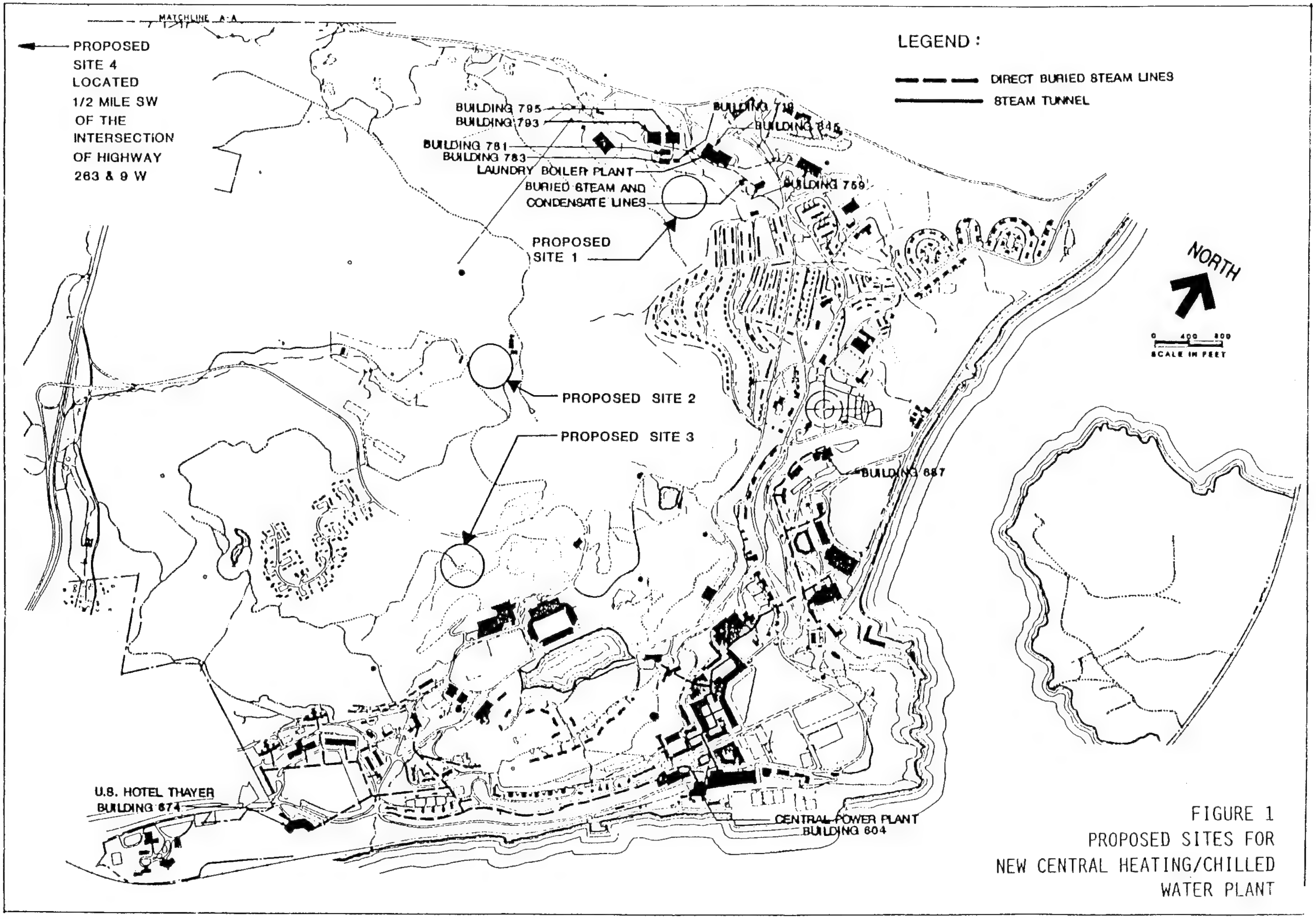

Figure 1. Proposed Sites for New Central Heating/Chilled Water Plant.

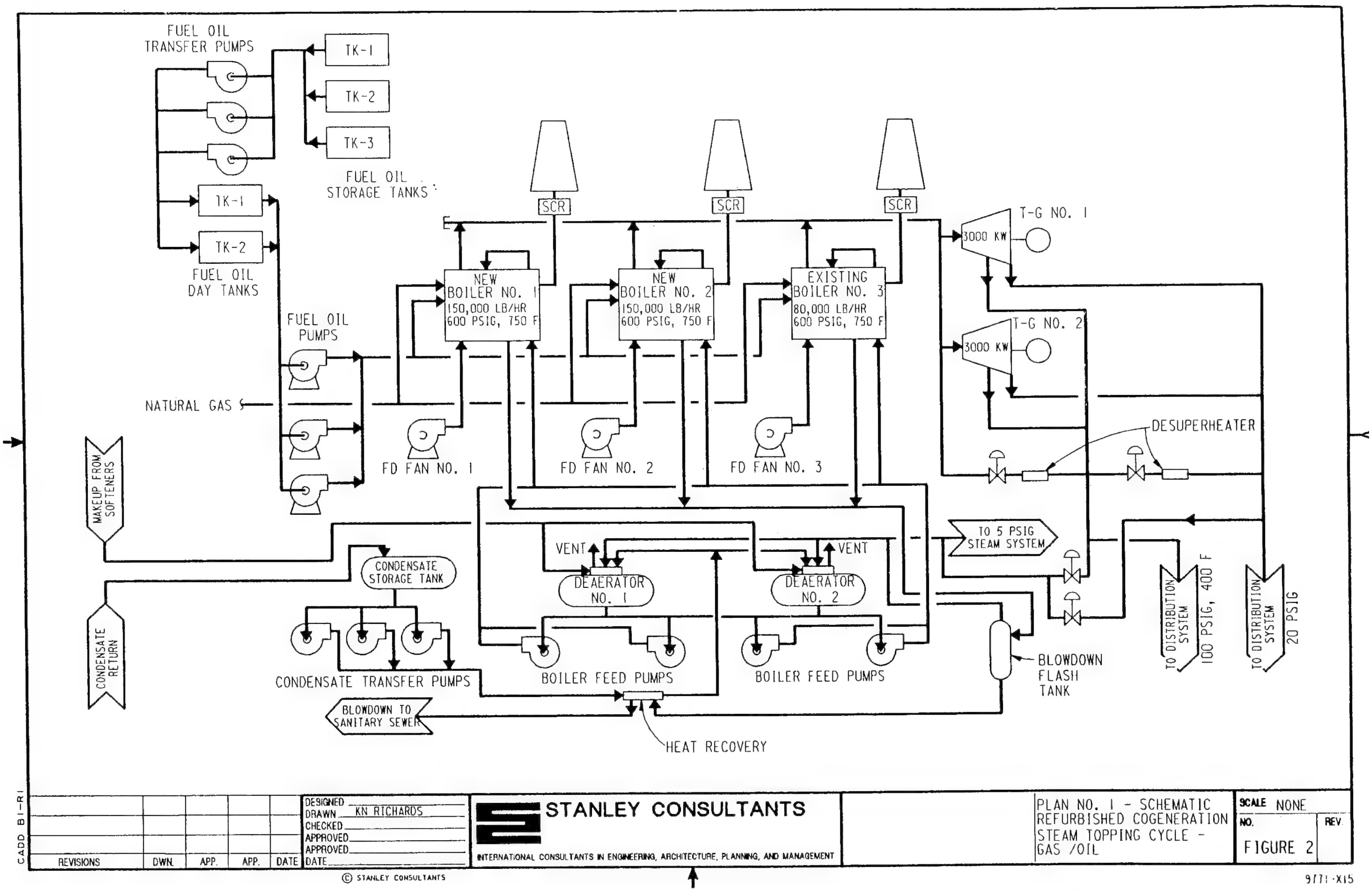

Figure 2. Schematic of Refurbished Cogeneration—Steam Topping Cycle—Gas/Oil.

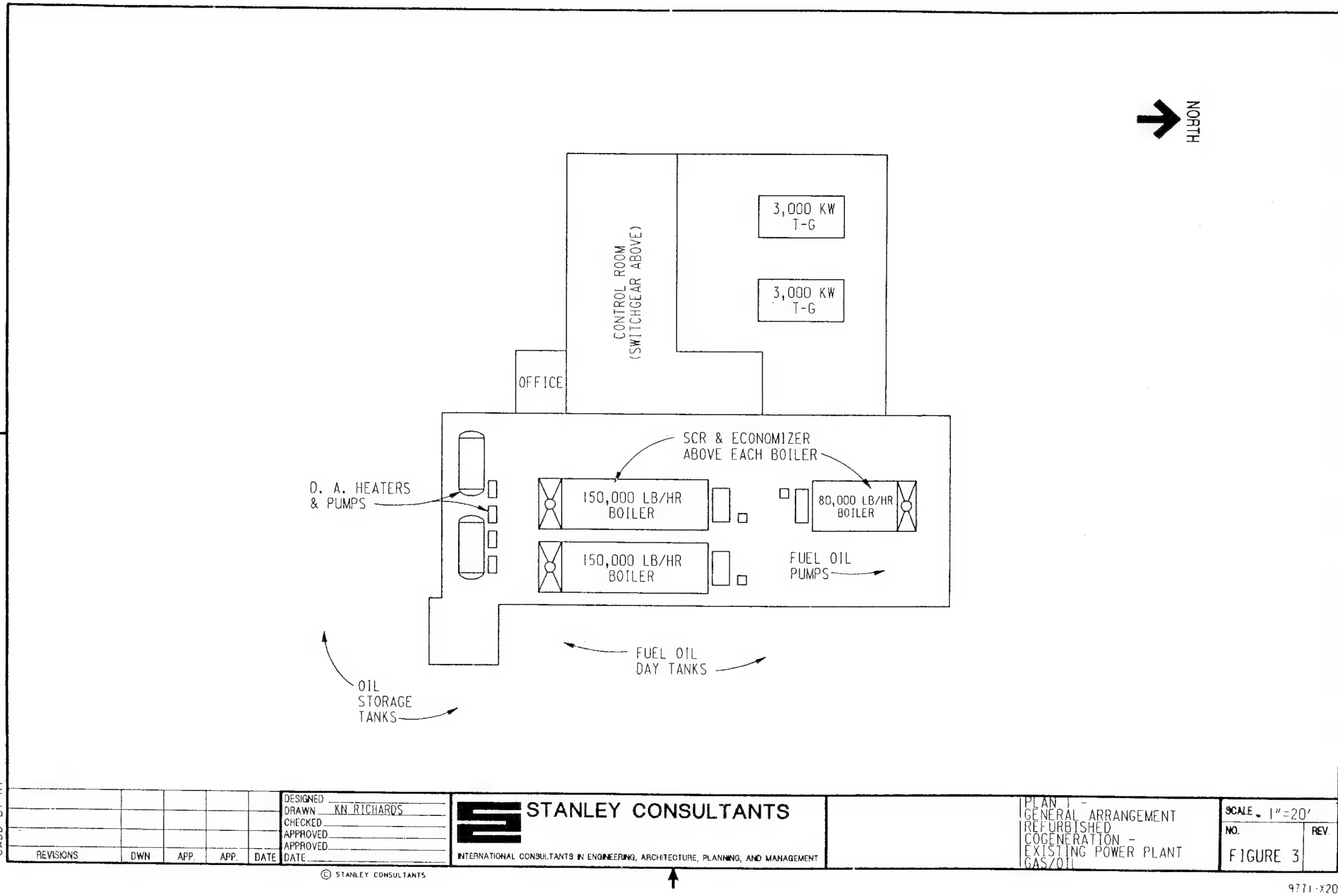

Figure 3. General Arrangement of Refurbished Cogeneration—Existing Power Plant—Gas/Oil.

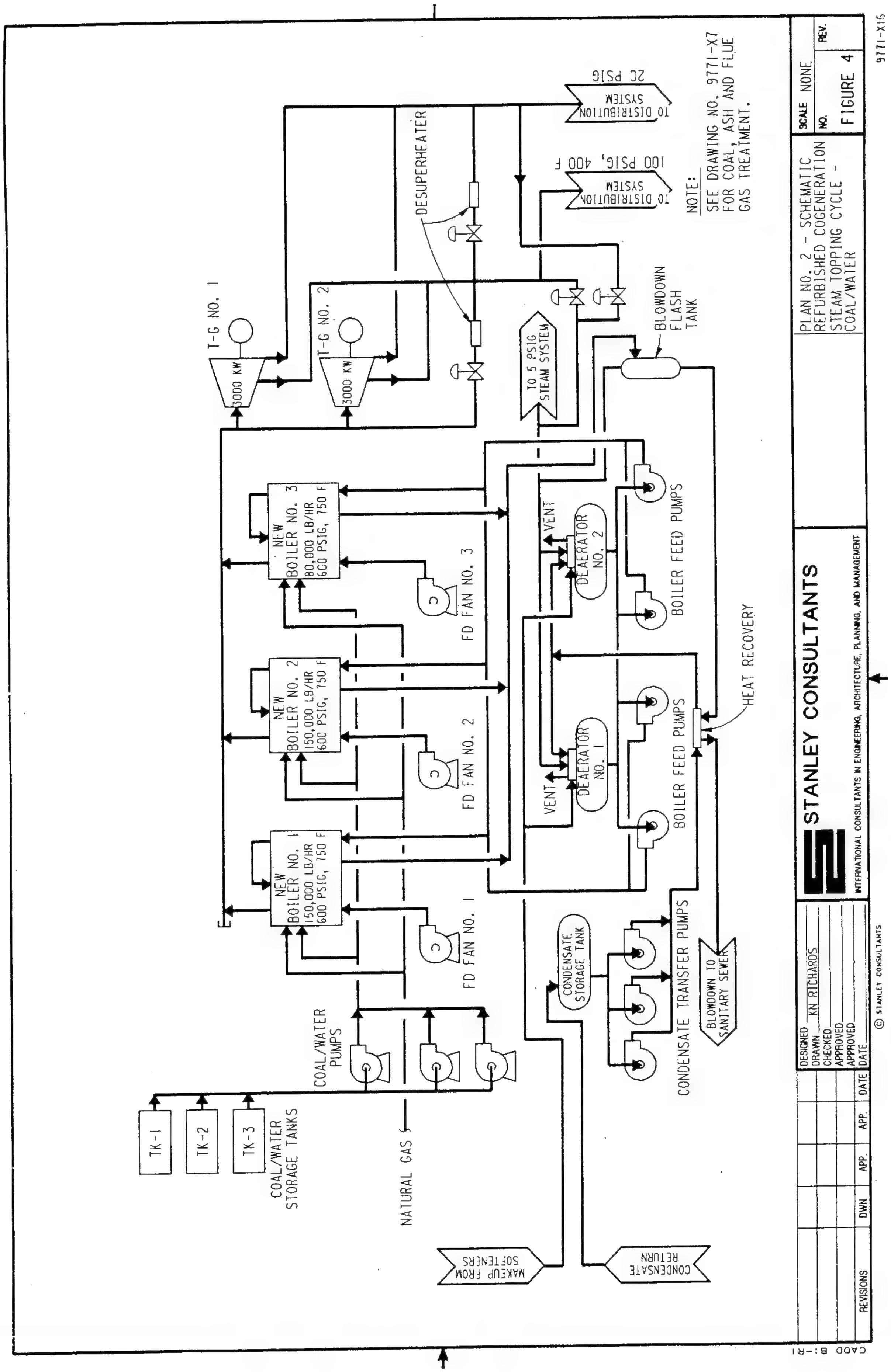

Figure 4. Schematic of Refurbished Cogeneration—Steam Topping Cycle—Gas/Oil.

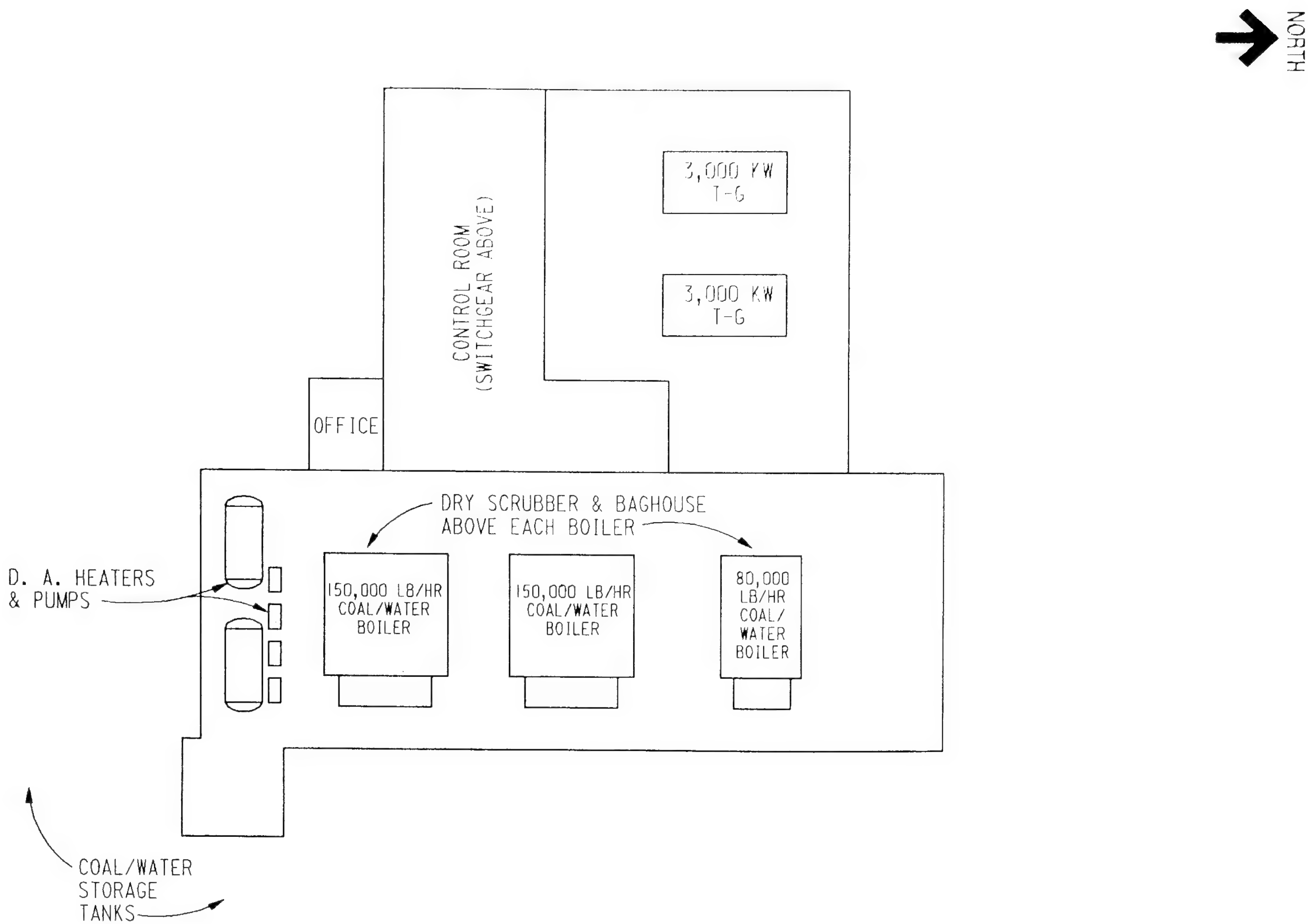

Figure 5. General Arrangement of Refurbished Cogeneration—Existing Power Plant—Coal/Water.

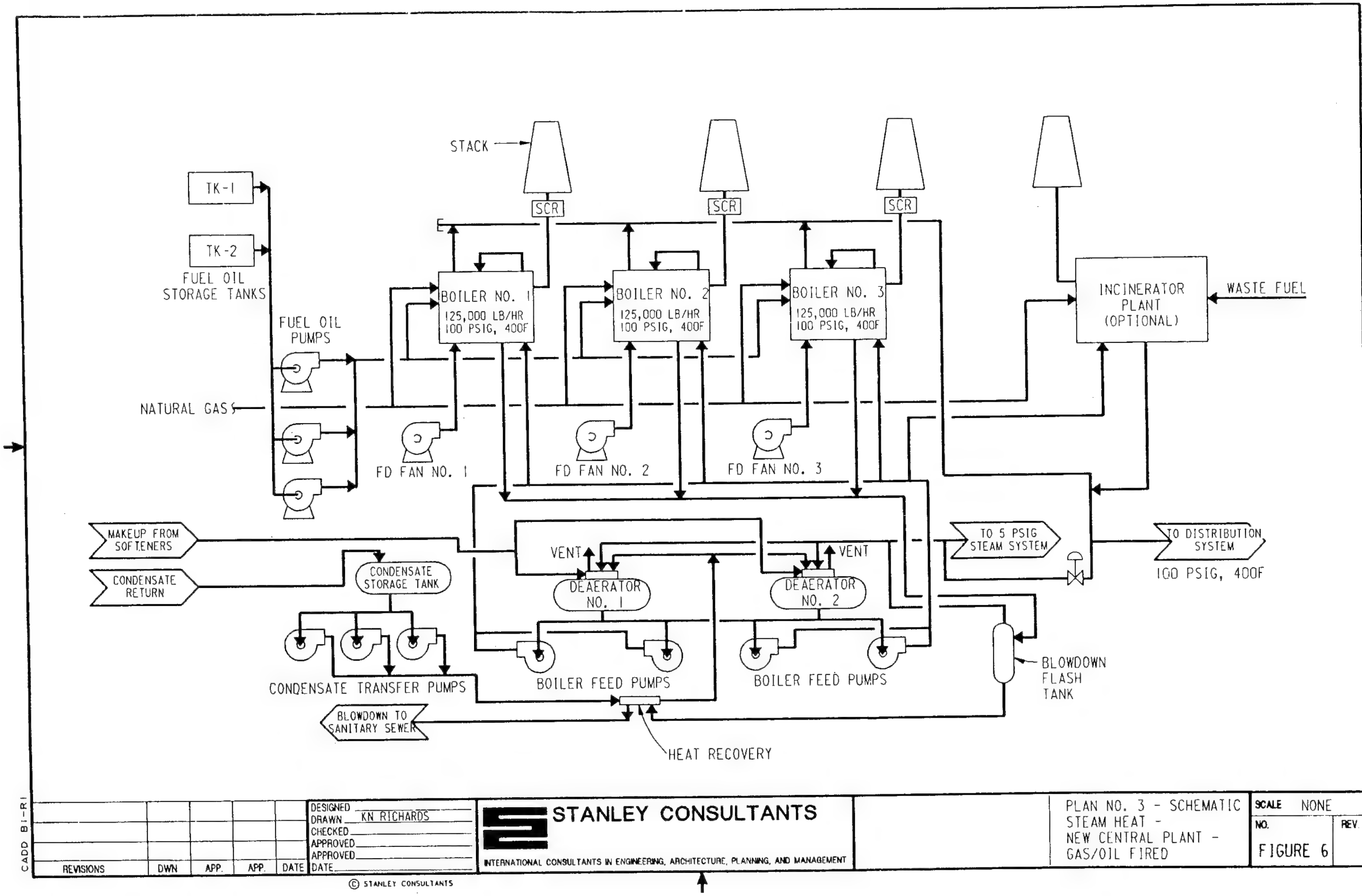

Figure 6. Schematic of Steam Heat—New Central Plant—Gas/Oil Fired.

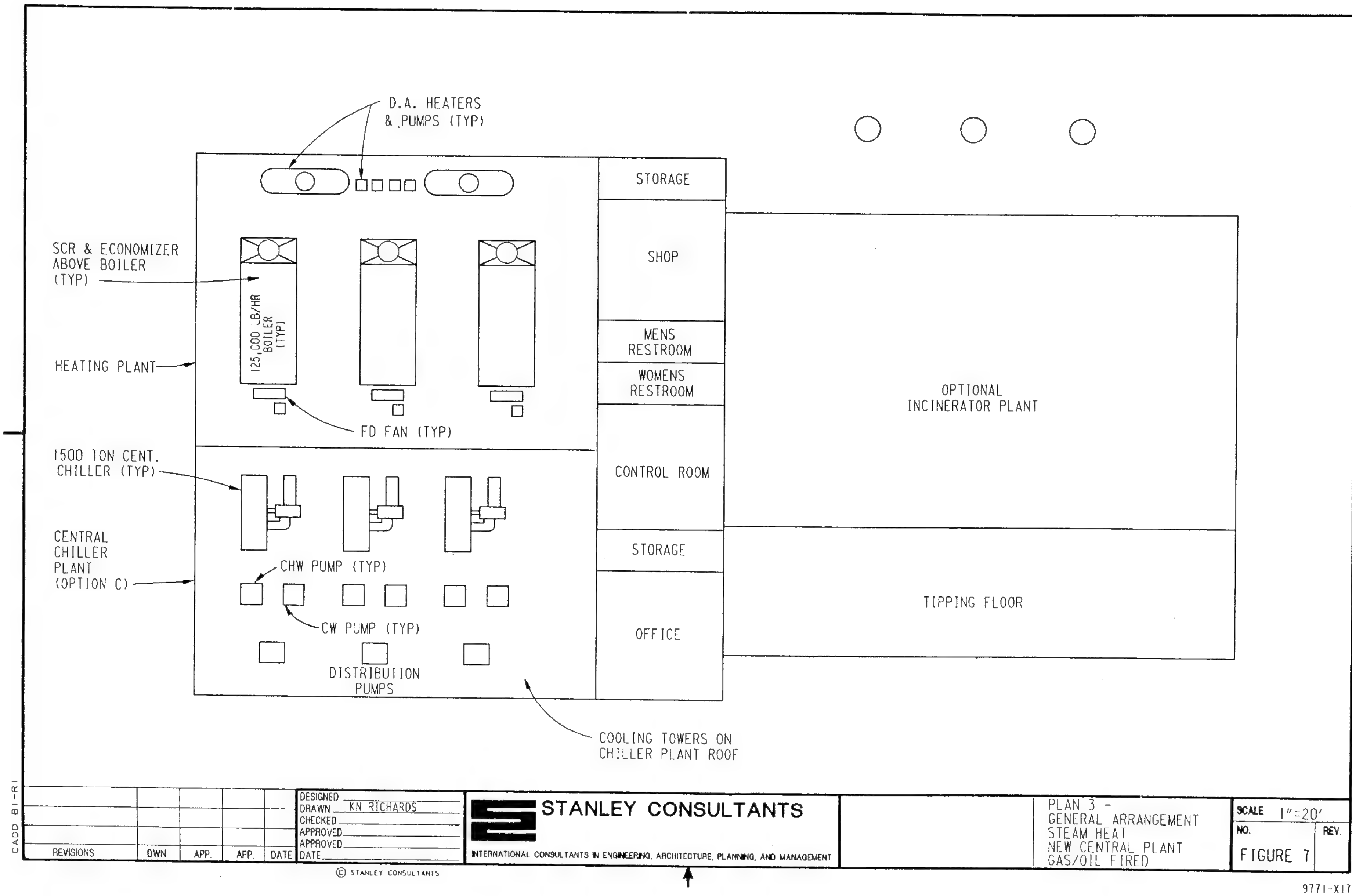

Figure 7. General Arrangement of Steam Heat—New Central Plant—Gas/Oil.

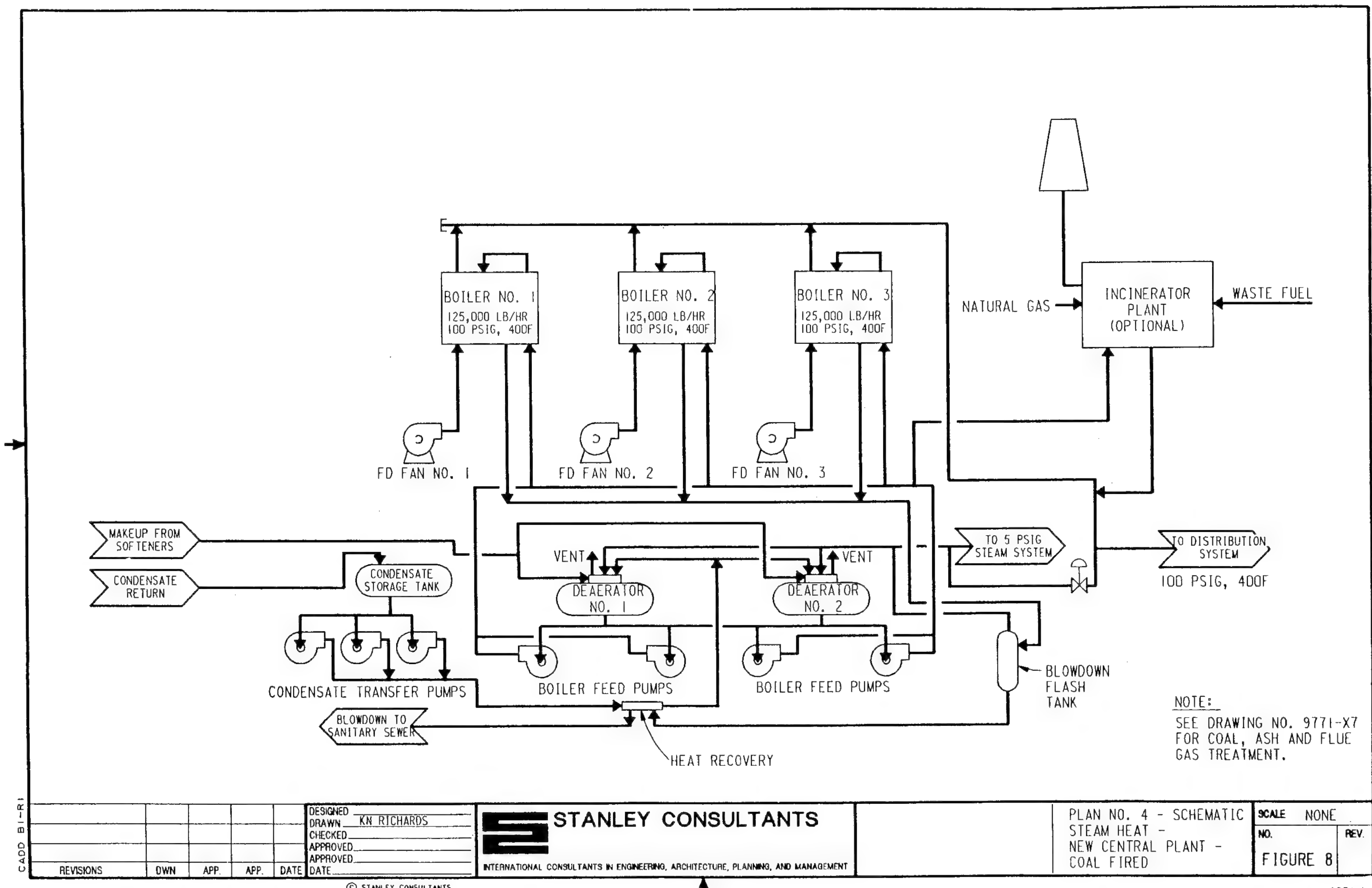

Figure 8. Schematic of Steam Heat—New Central Plant—Coal.

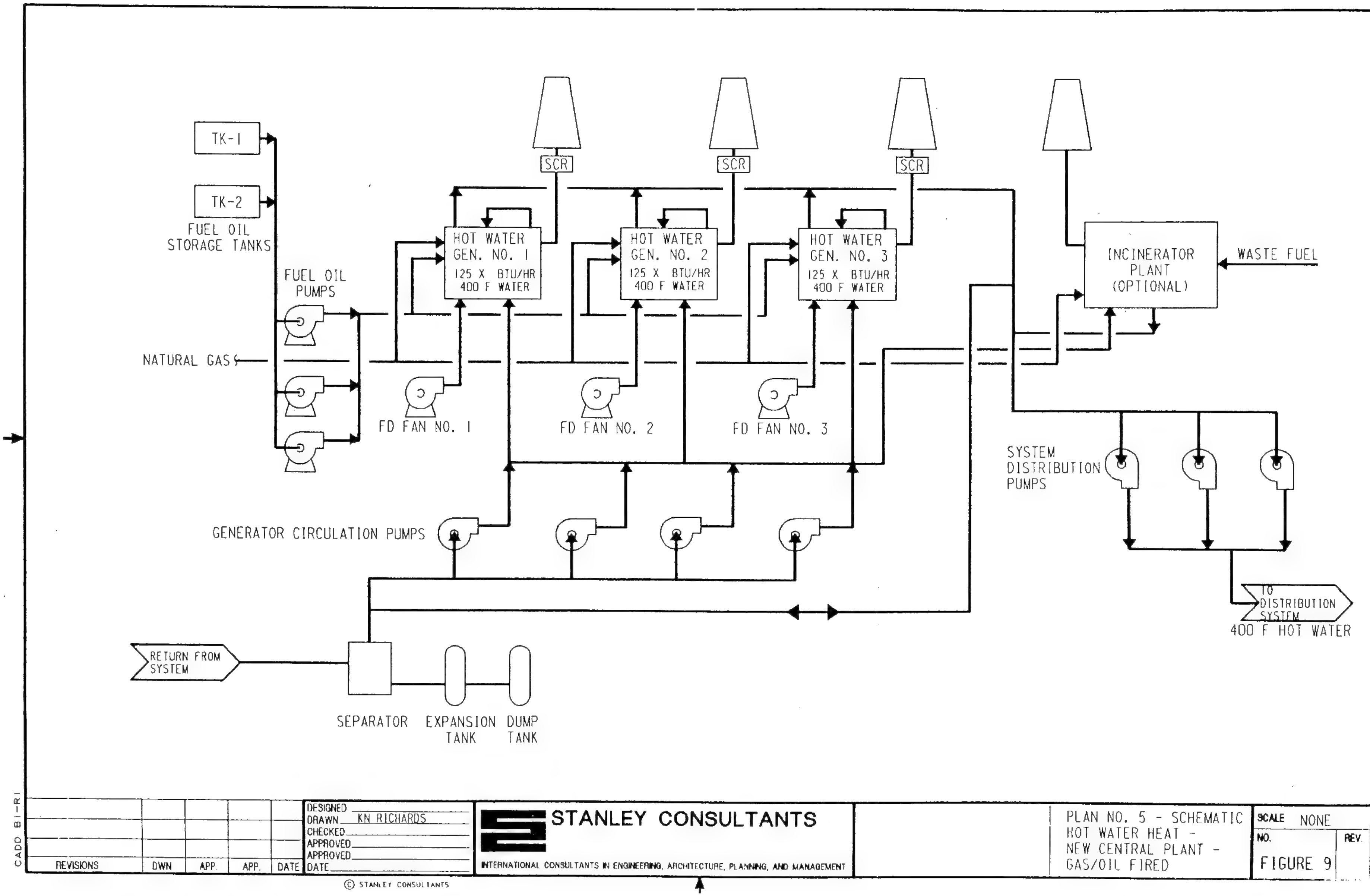

Figure 9. Schematic of Hot Water Heat—New Central Plant—Gas/Oil.

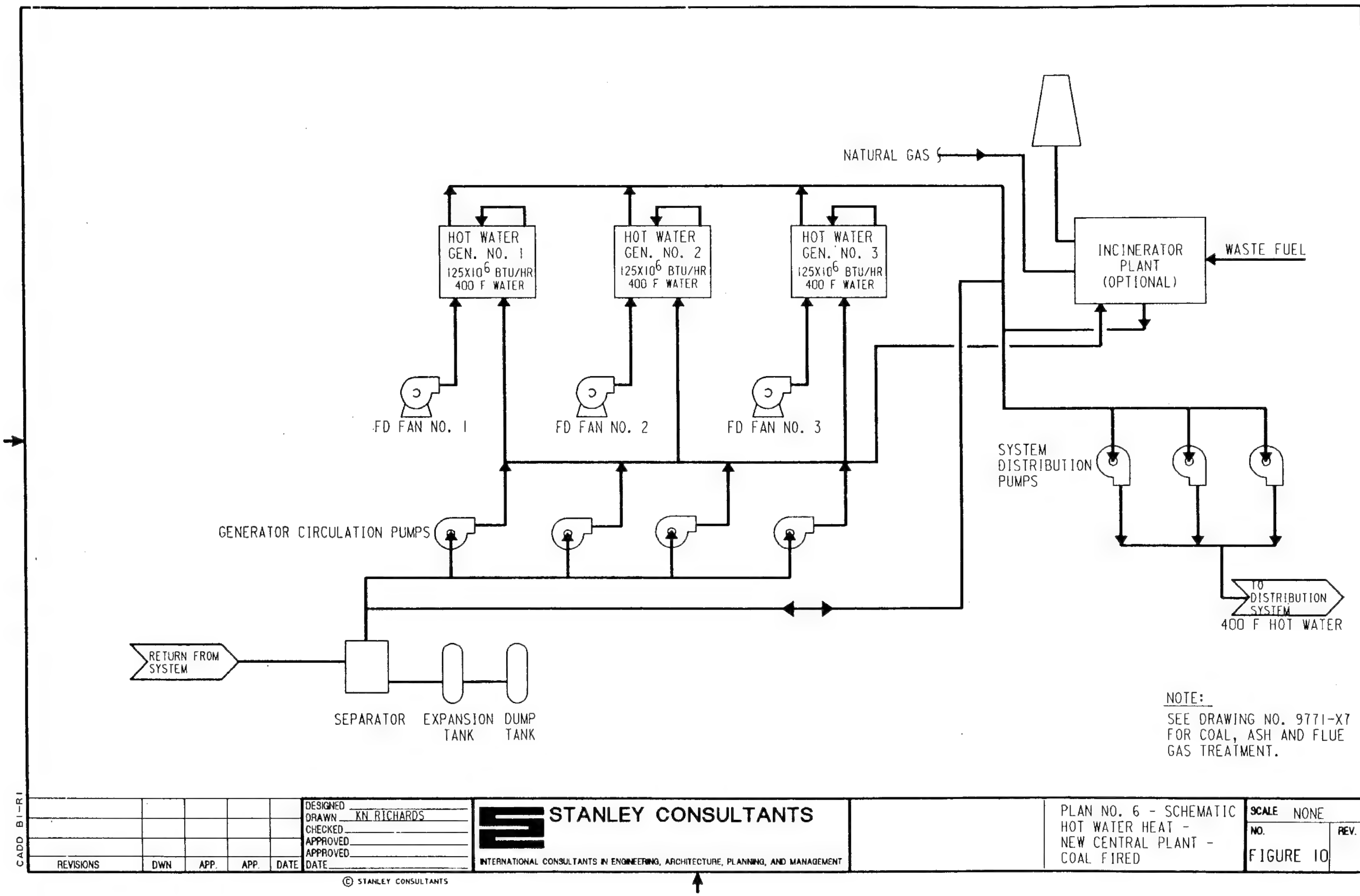

Figure 10. Schematic of Hot Water Heat—New Central Plant—Coal.

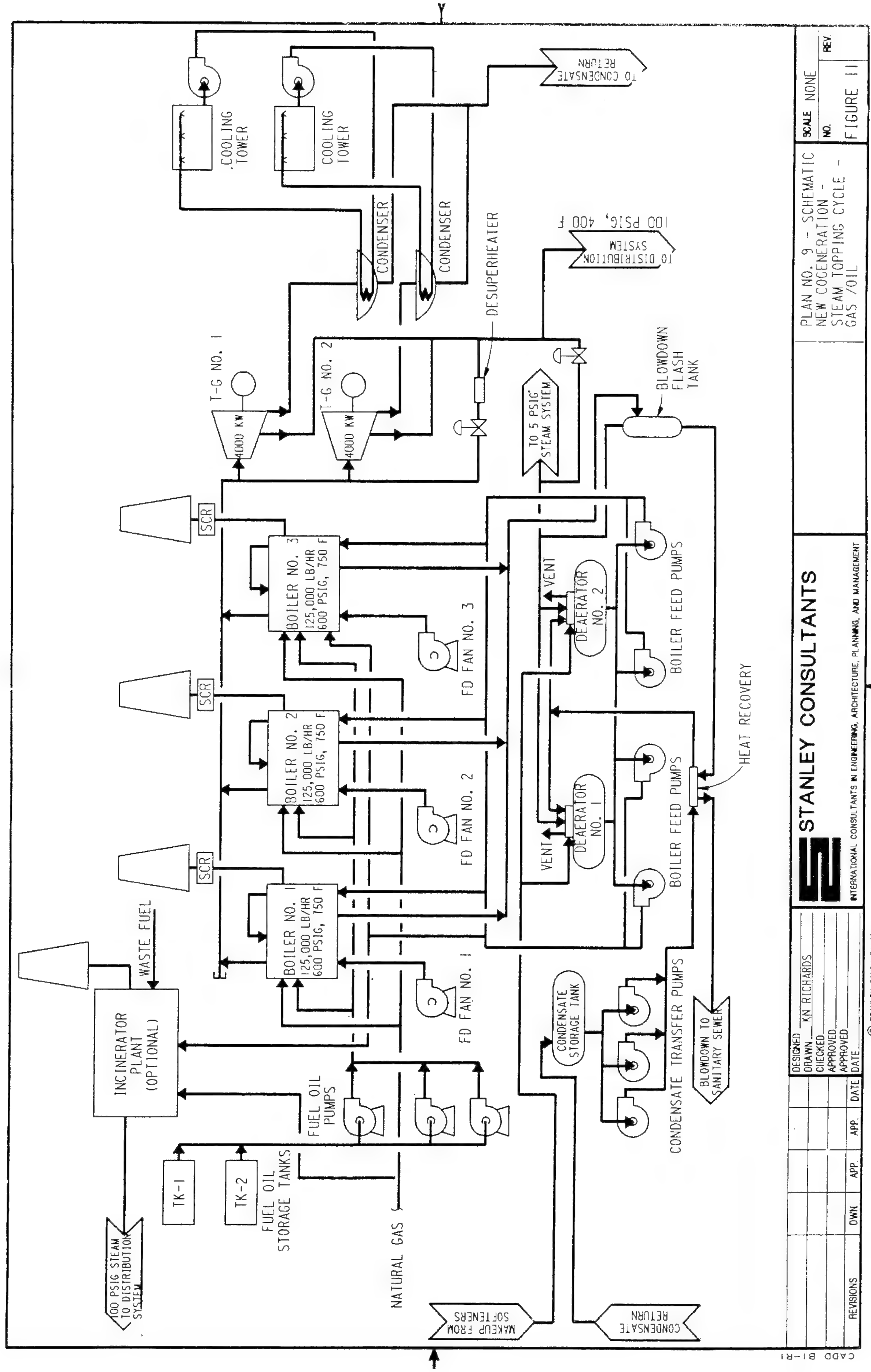

Figure 11. Schematic of New Cogeneration—Steam Topping Cycle—Gas/Oil.

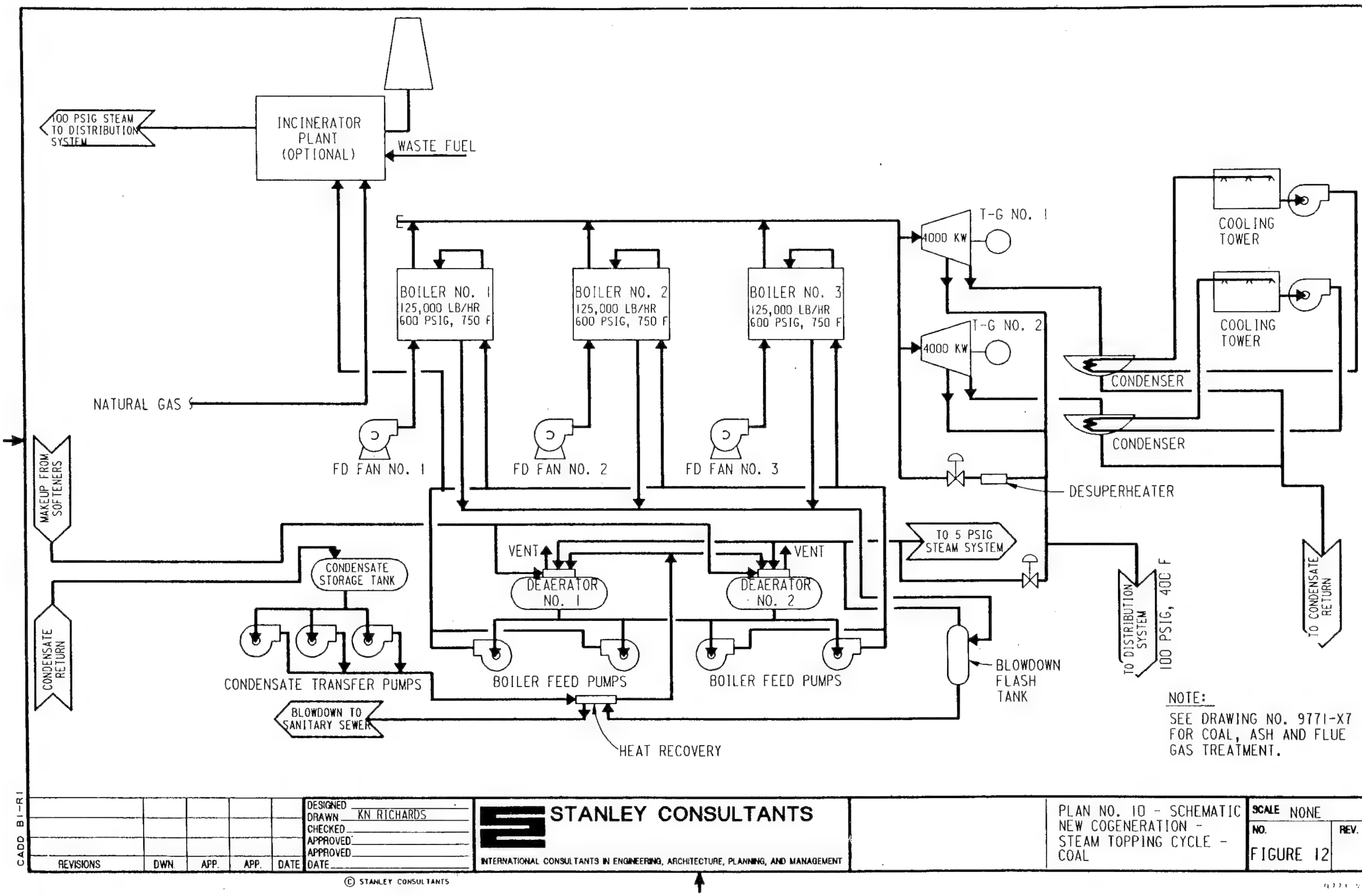

Figure 12. Schematic of New Cogeneration—Steam Topping Cycle—Coal.

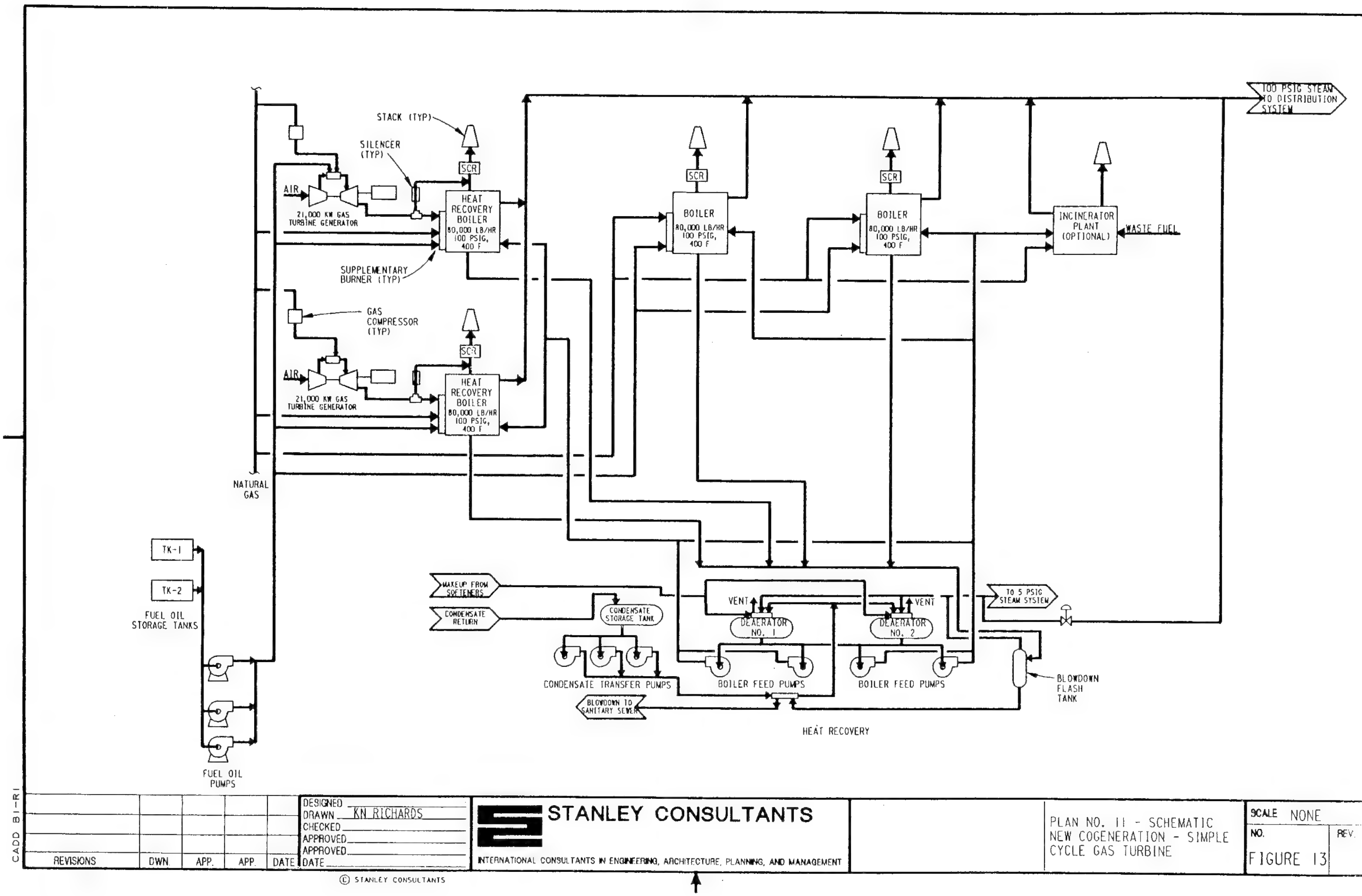

Figure 13. Schematic of New Cogeneration—Simple Cycle Gas Turbine.

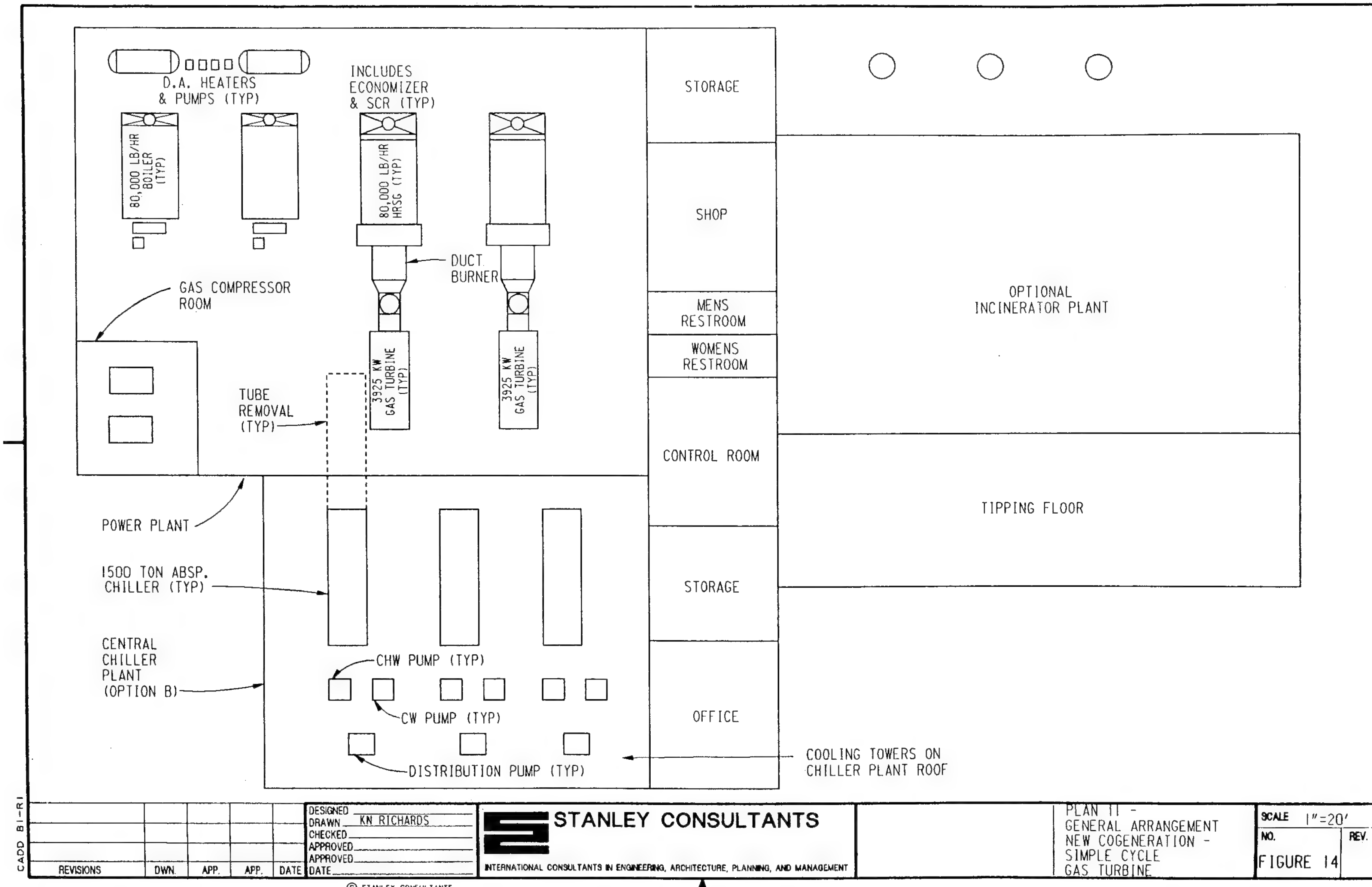

Figure 14. General Arrangement of New Cogeneration—Simple Cycle Gas Turbine.

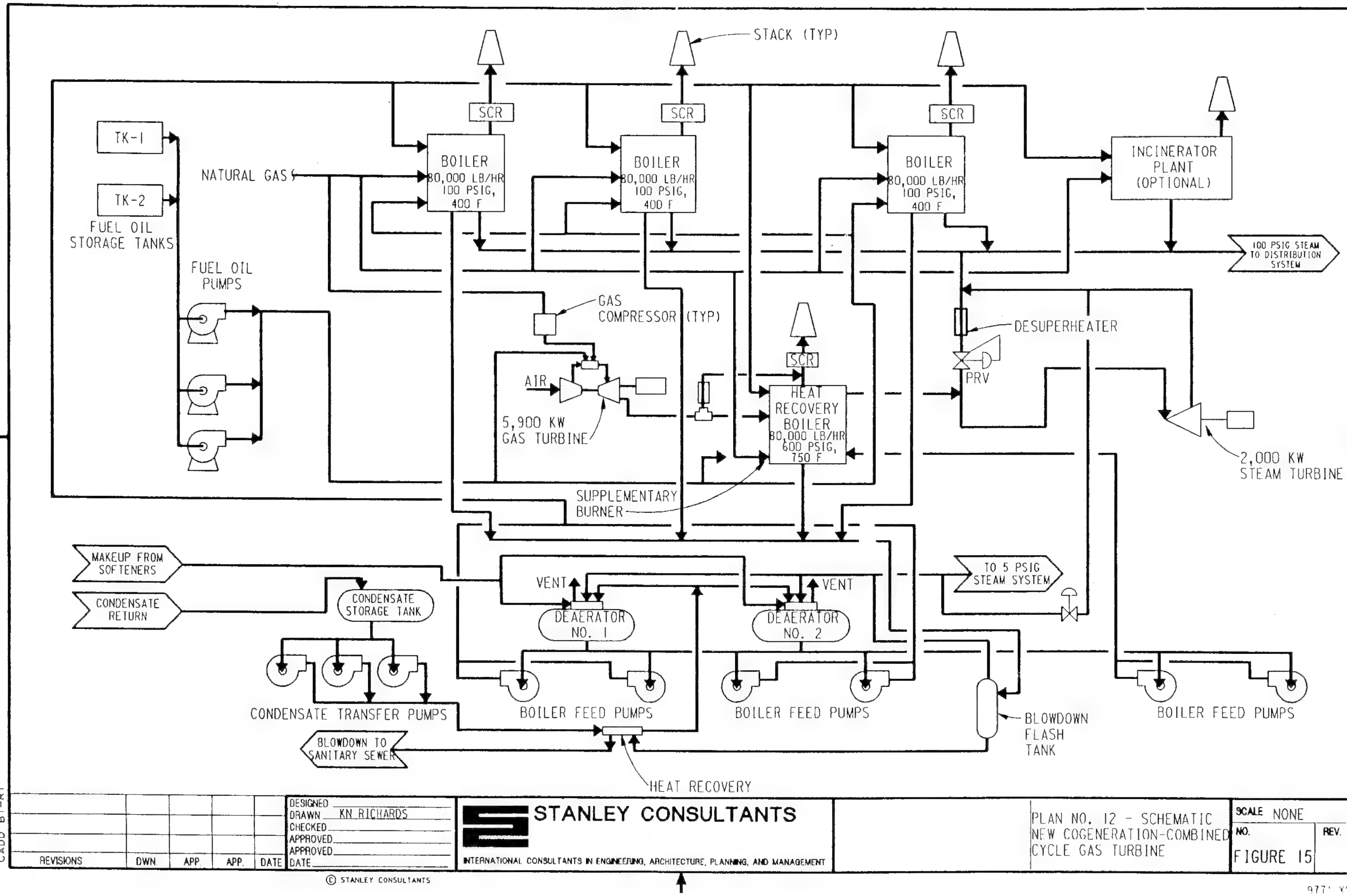

Figure 15. Schematic of New Cogeneration—Combined Cycle Gas Turbine.

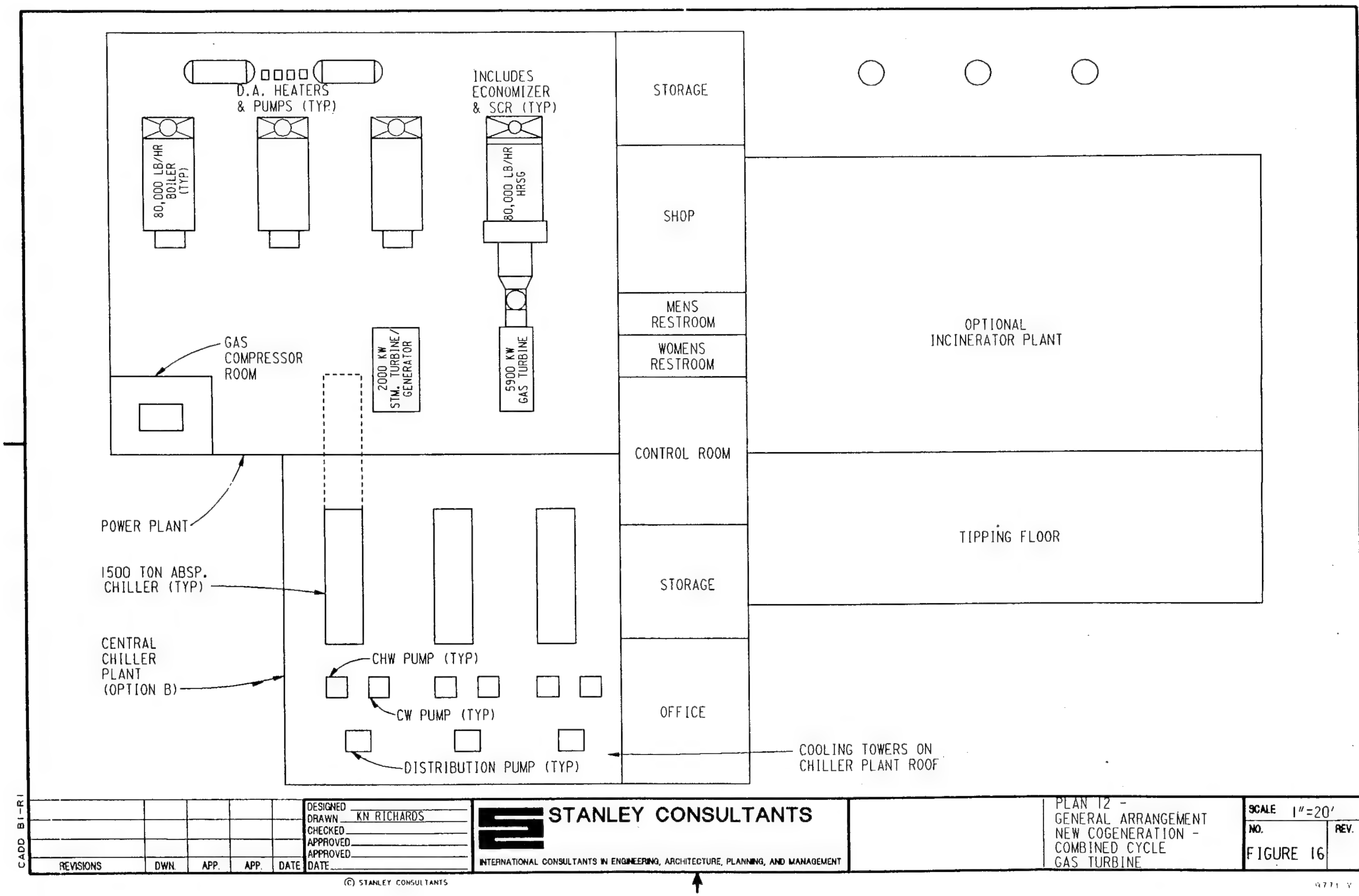

Figure 16. General Arrangement of New Cogeneration—Combined Cycle Gas Turbine.

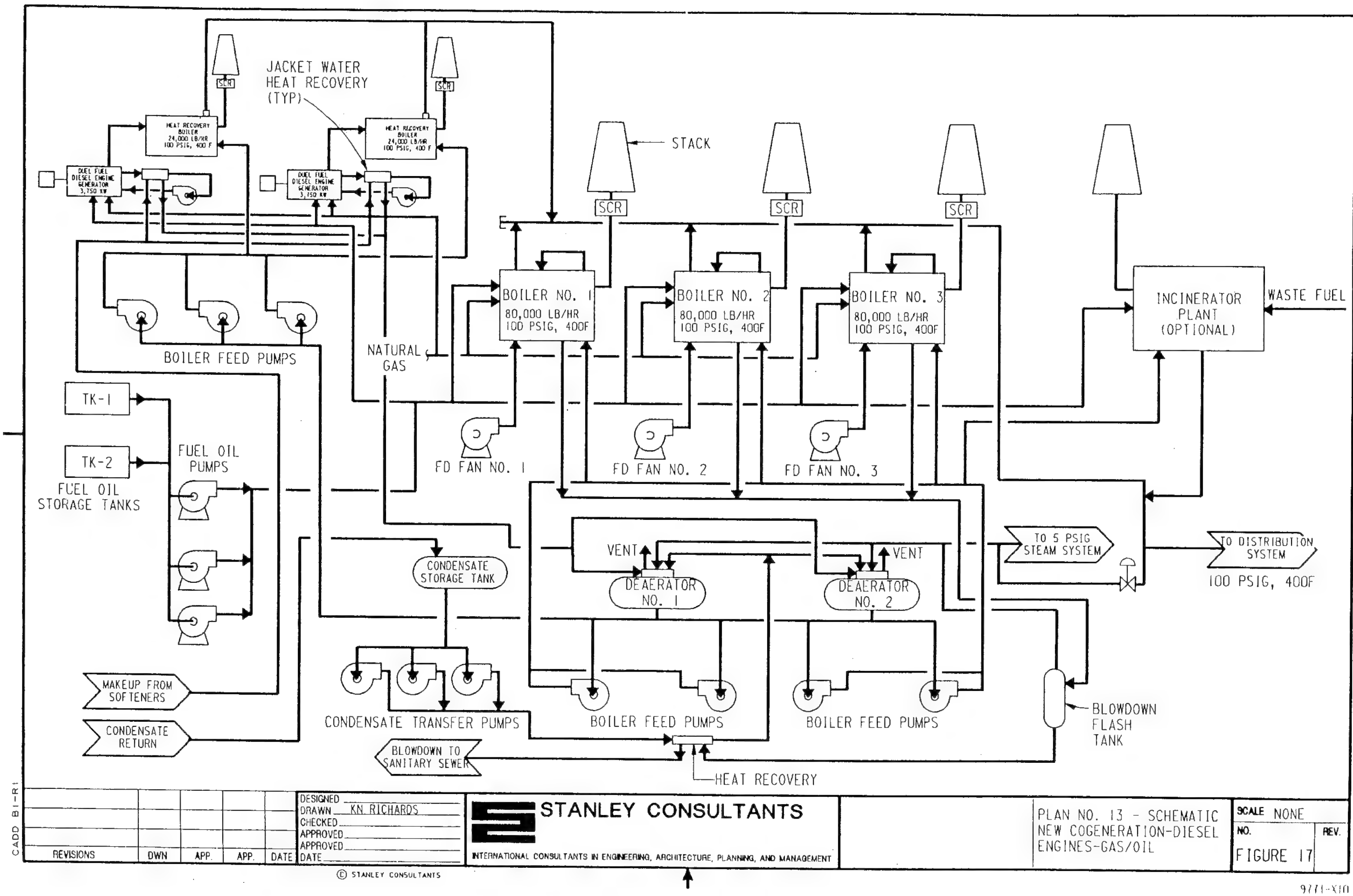

Figure 17. Schematic of New Cogeneration—Diesel Engines—Gas/Oil.

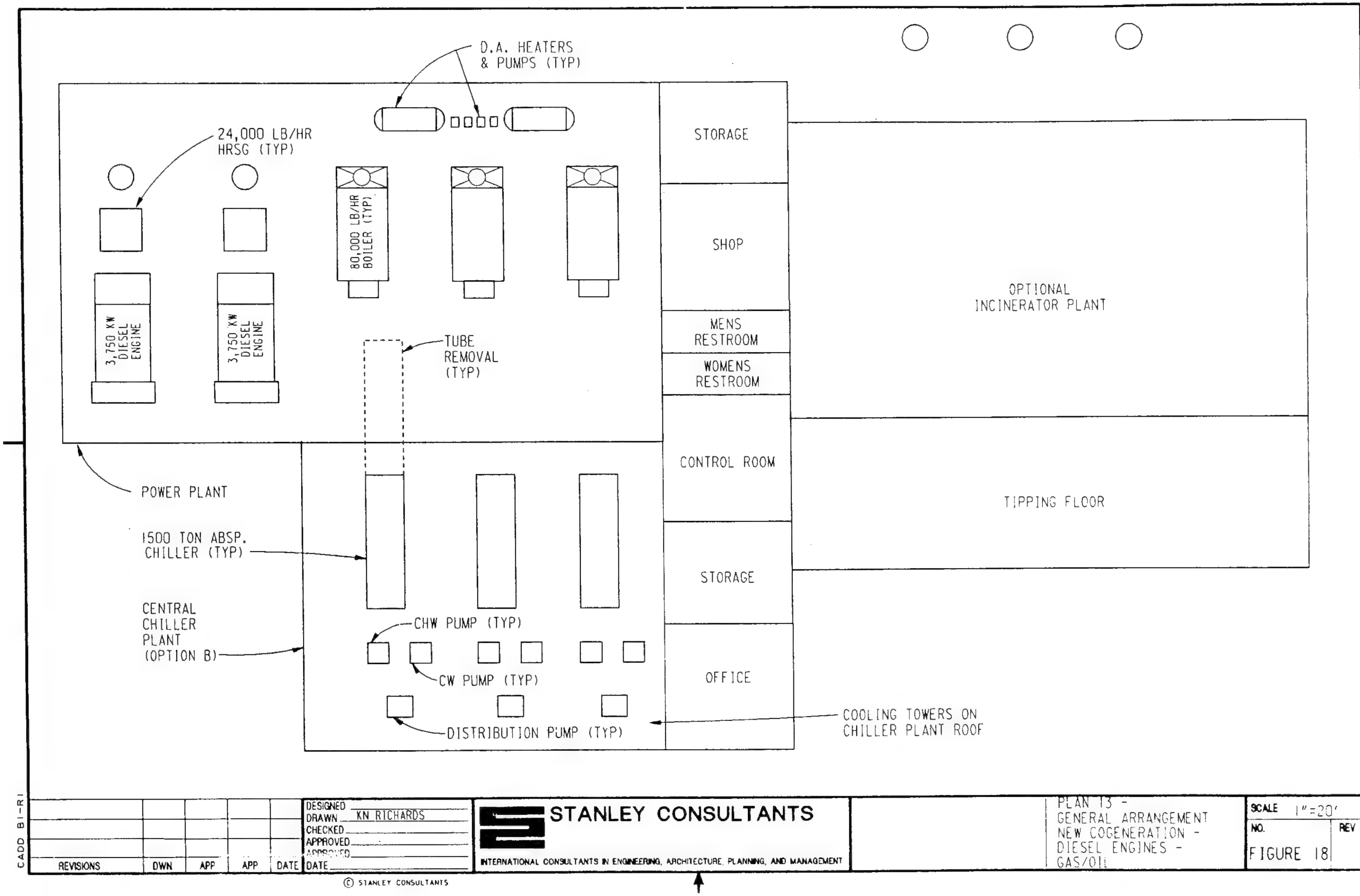

Figure 18. General Arrangement of New Cogneration—Diesel Engines—Gas/Oil.

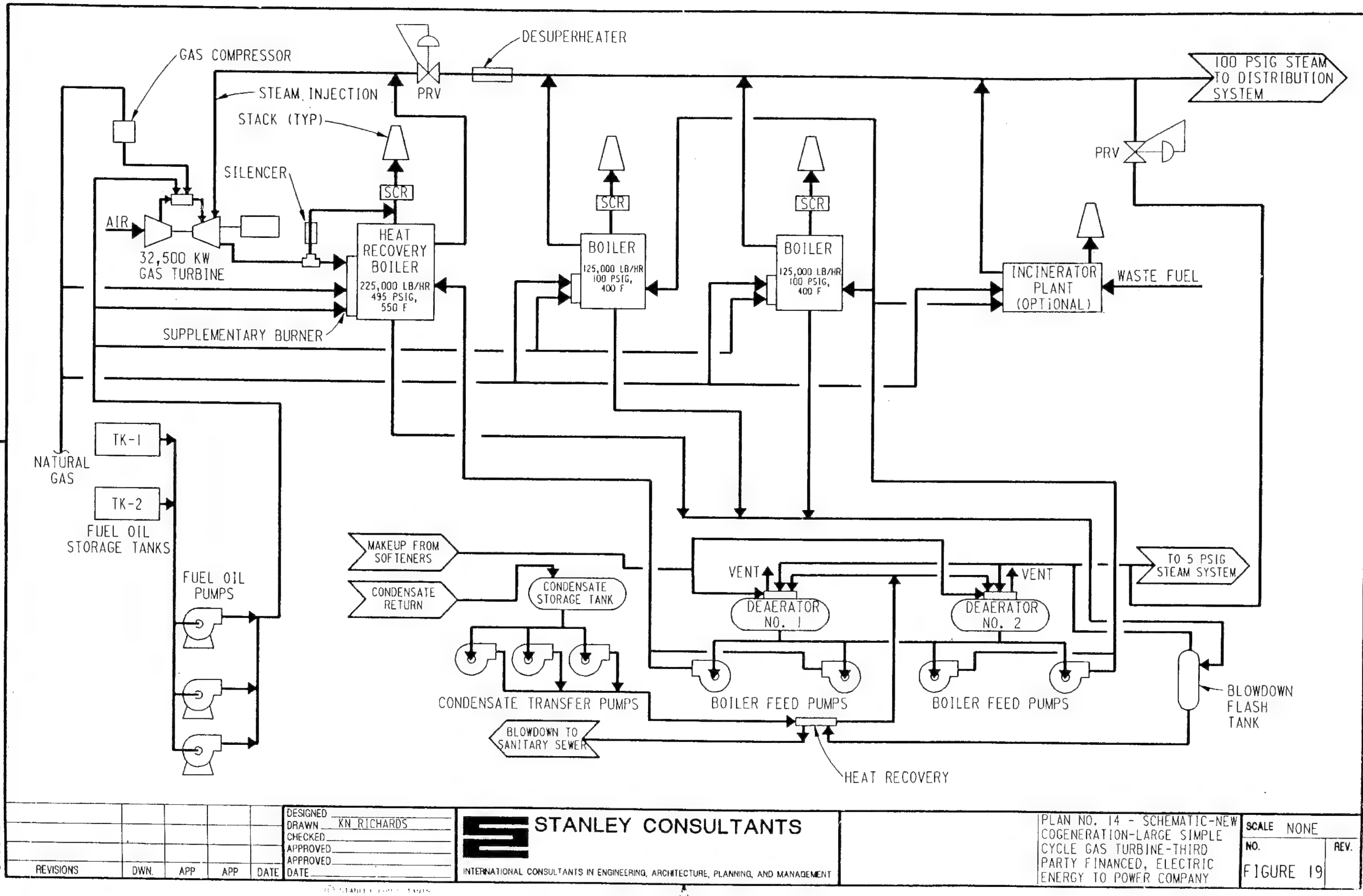

Figure 19. Schematic of New Cogeneration—Large Simple Cycle Gas Turbine.

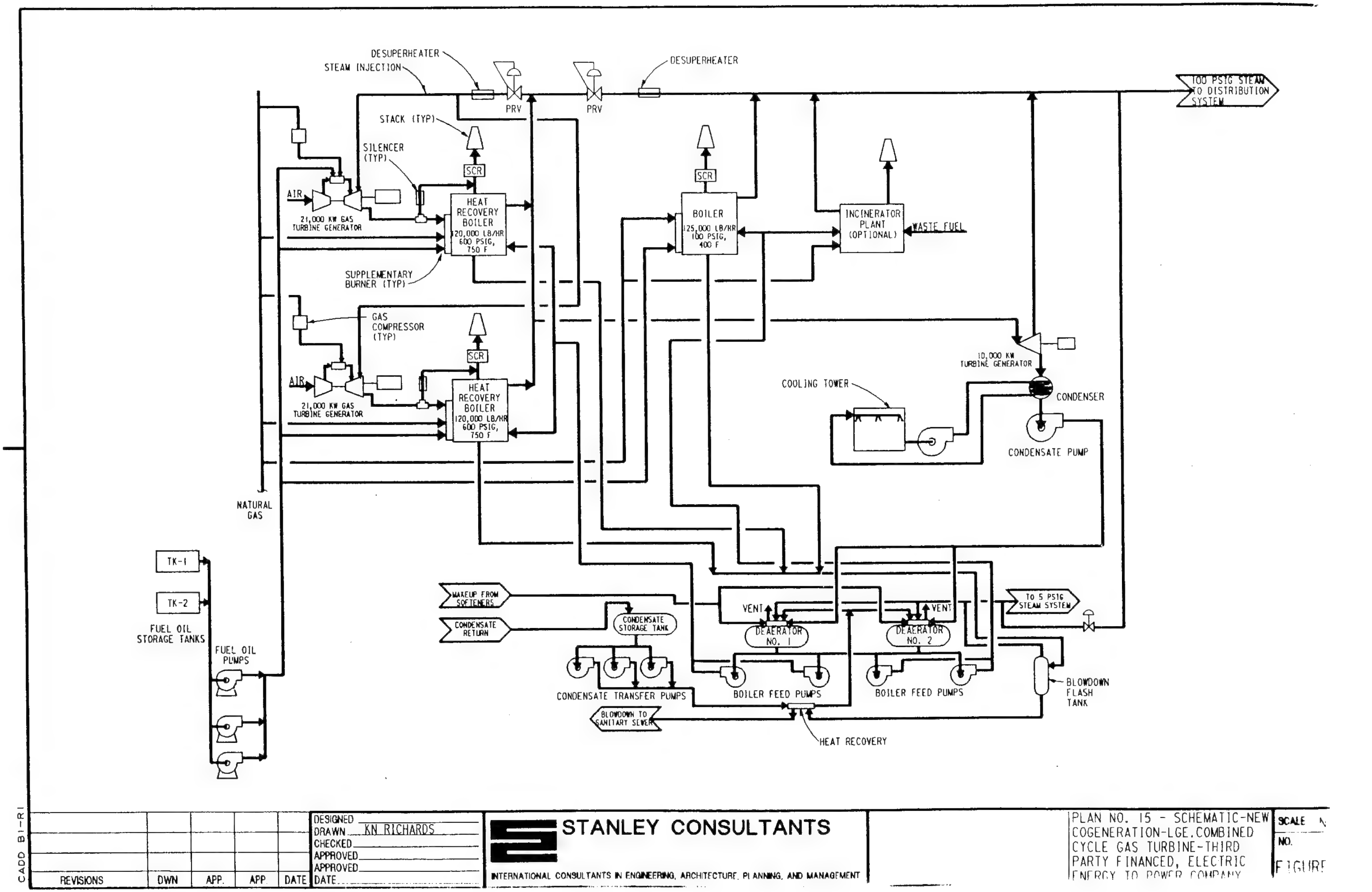

Figure 20. Schematic of New Cogeneration—Large Combined Cycle Gas Turbine.

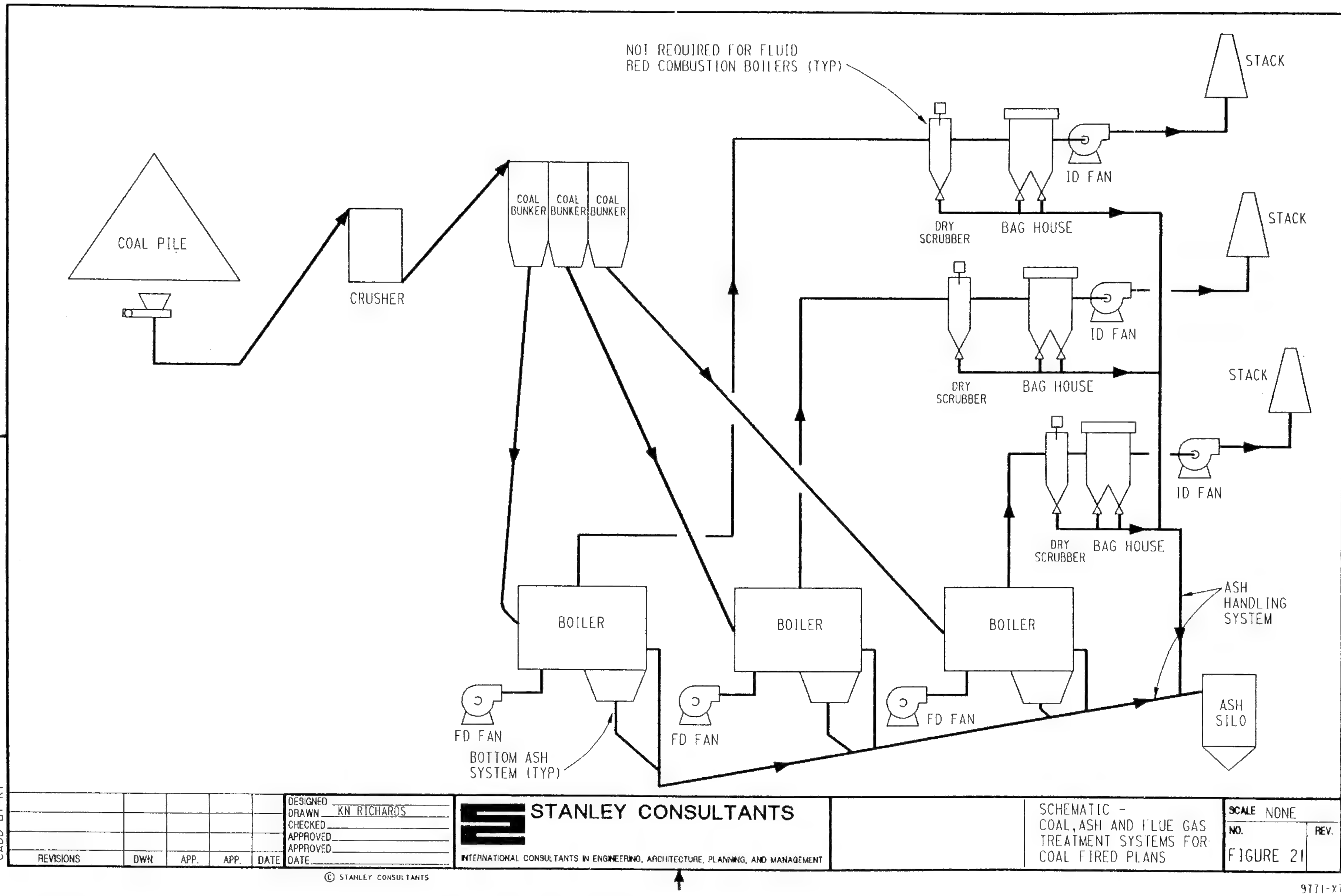

Figure 21. Schematic of Coal, Ash, and Flue Gas Treatment Systems for Coal-Fired Plans.

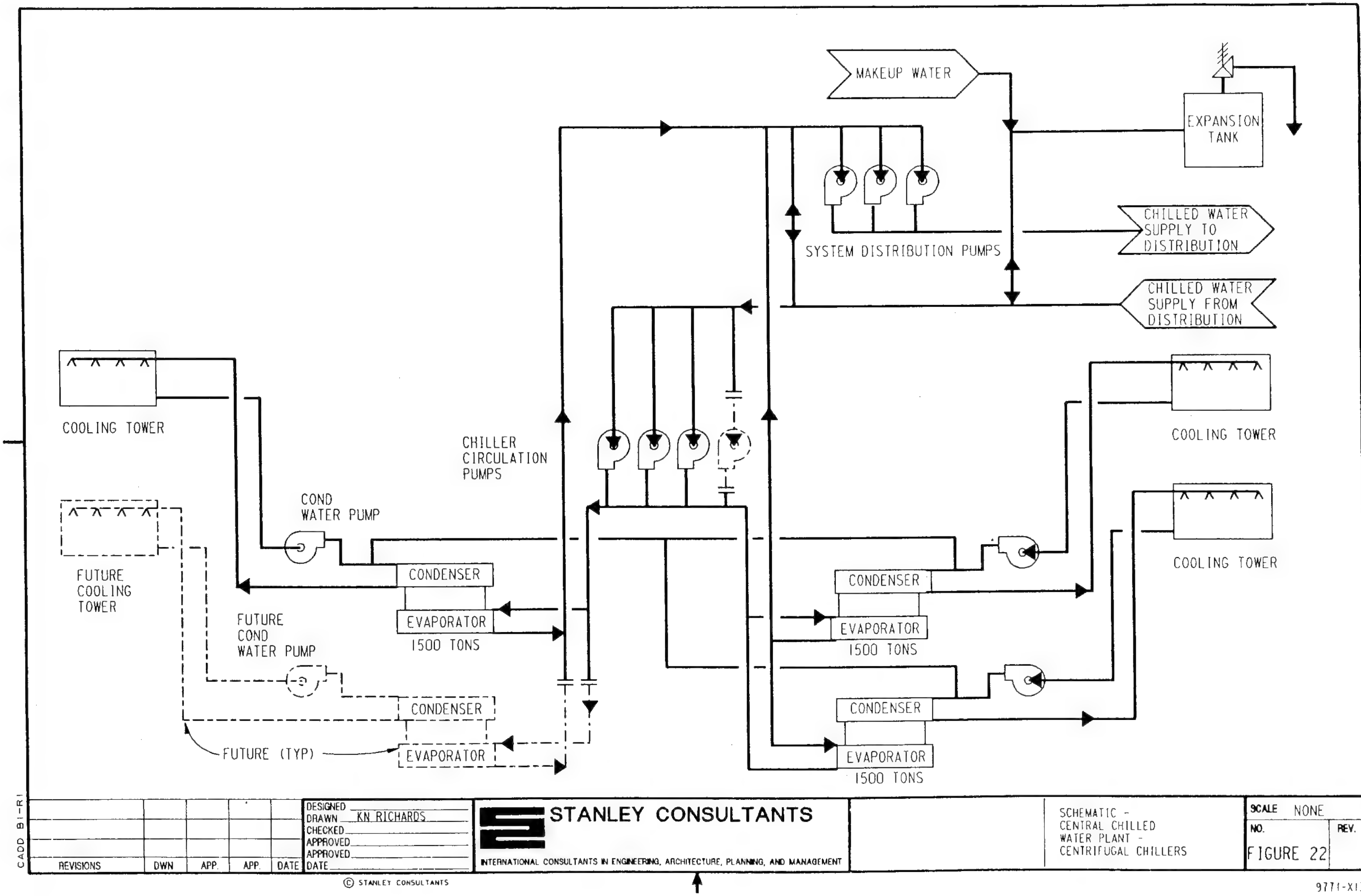

Figure 22. Schematic of Central Chilled Water Plant—Centrifugal Chillers.

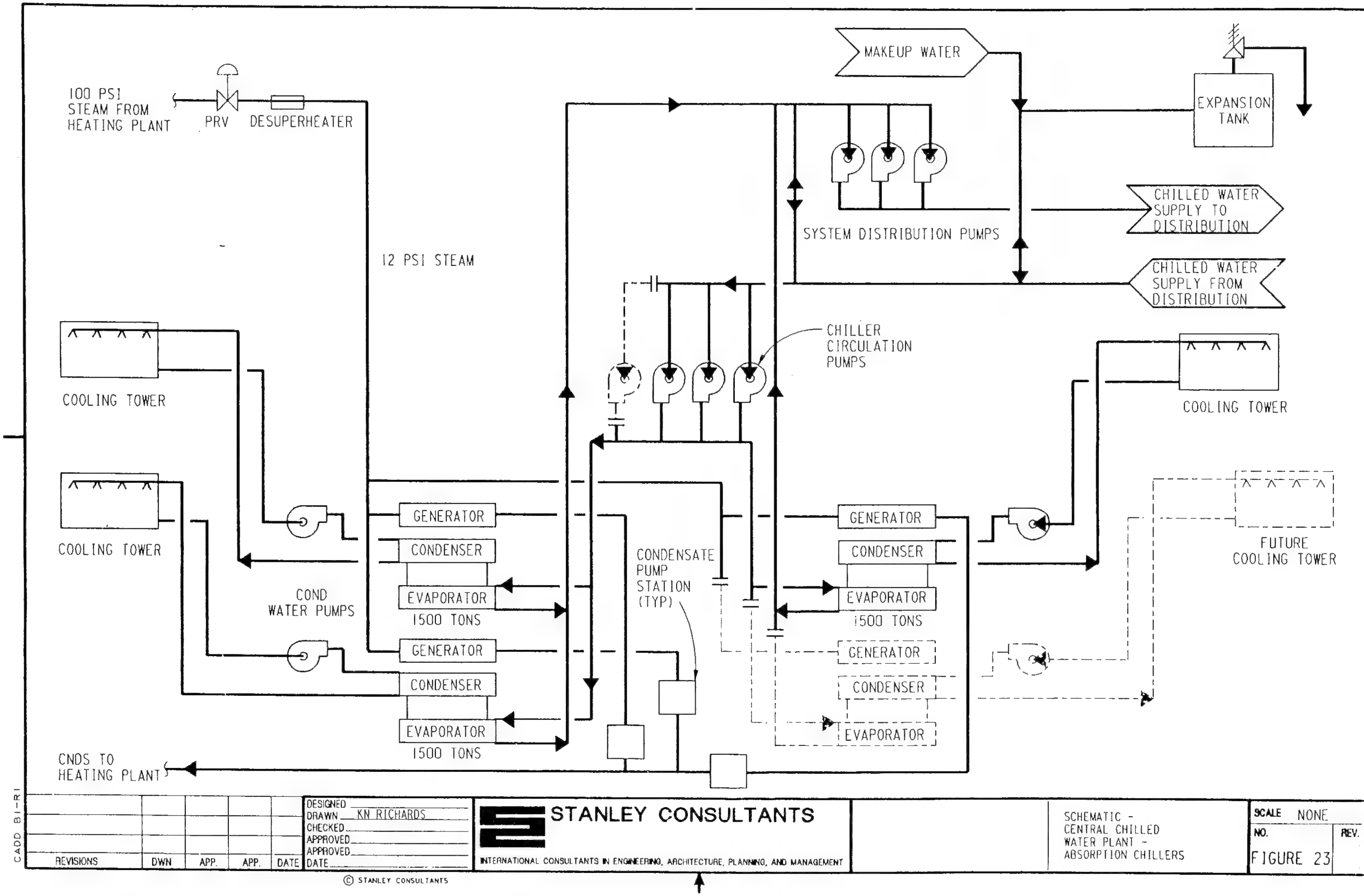

Figure 23. Schematic of Central Chilled Water Plant—Absorption Chillers.

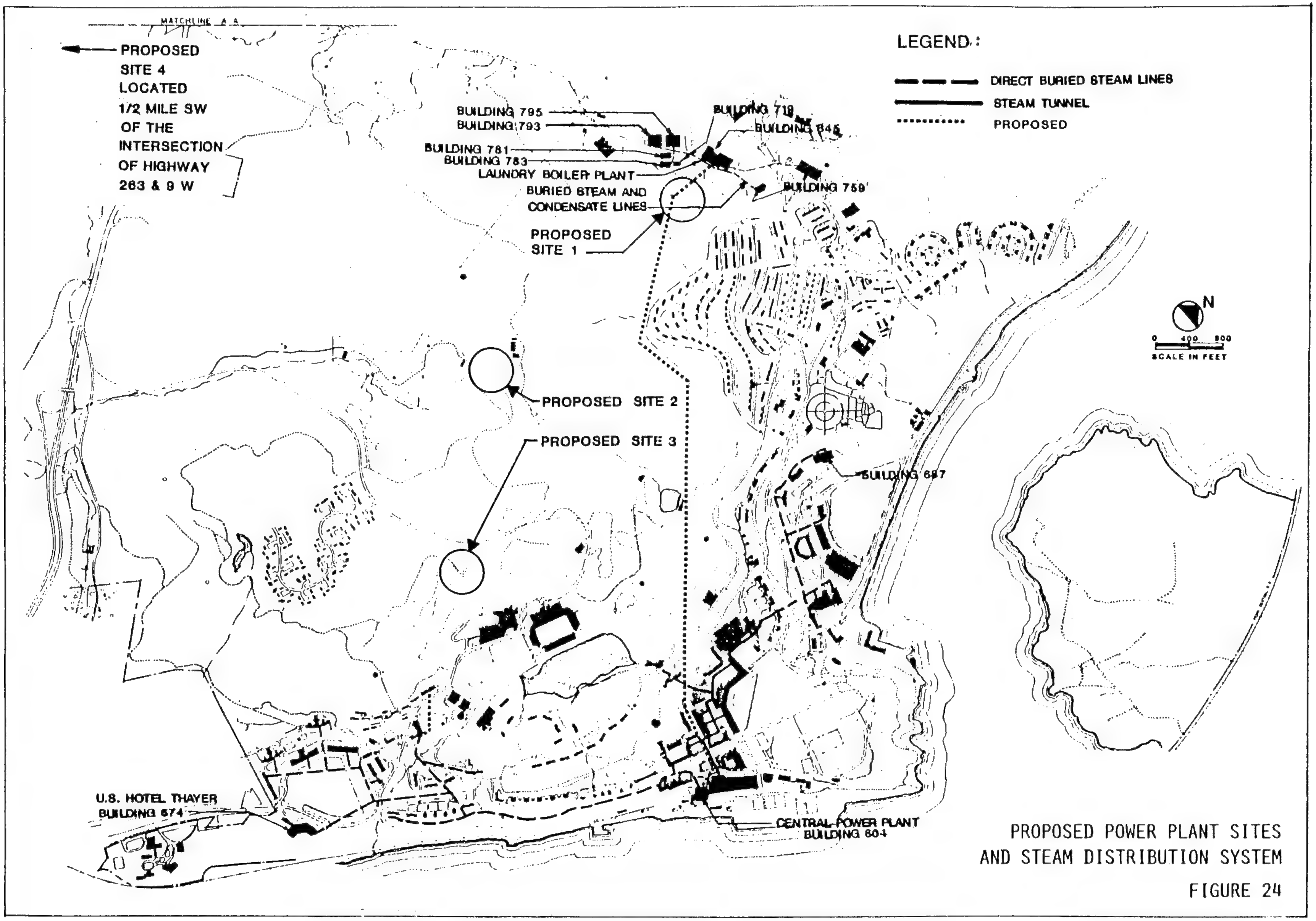

Figure 24. Proposed Power Plant Sites and Steam Distribution Systems.

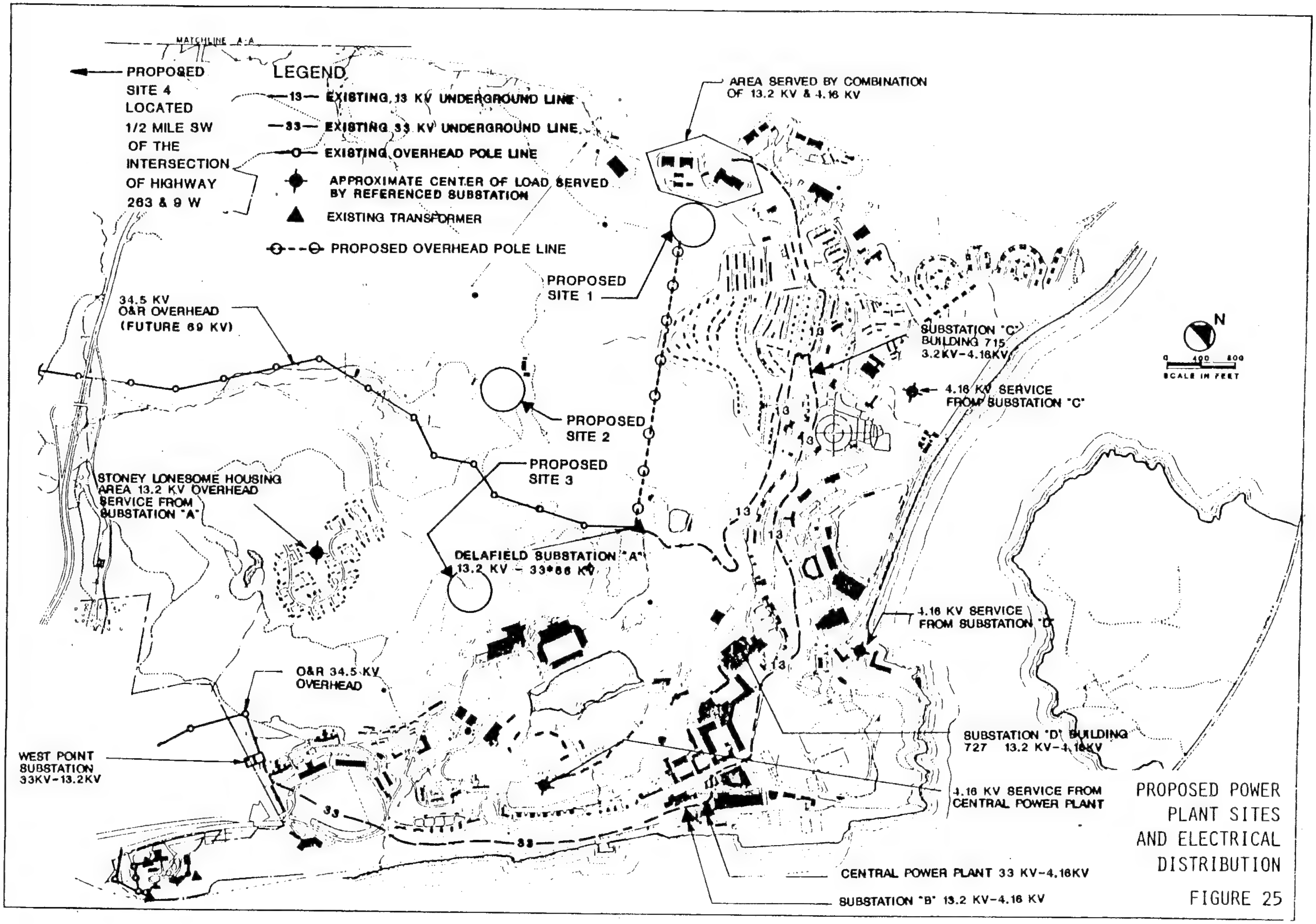

Figure 25. Proposed Power Plant Sites and Electrical Distribution.

5 ENVIRONMENTAL REGULATIONS AND CONSIDERATIONS

General

Several environmental aspects must be considered when planning construction of new fossil fuel-fired thermal and electric generating facilities. The primary environmental concerns include storage and handling of fuel, particulate and gaseous pollutant emissions during combustion, and disposal of liquid and solid wastes. Federal and state guidelines and regulations have been promulgated to mitigate environmental degradation resulting from fossil fuel combustion. The following sections summarize the various environmental concerns and the regulations governing them. Although this research did not consider public opinion in determining environmental impact and evaluating the feasibility of alternatives, public input must be considered in developing environmental assessments and environmental impact statements.

Environmental Assessment and Environmental Impact Statement

Section 102 of the National Environmental Policy Act (NEPA) requires that environmental statements be prepared for "major federal actions significantly affecting the quality of the human environment." While the definition of major action or significant effect is not defined, construction of a new or substantial modification of an existing fossil-fuel burning facility would be considered a major action.

The lead reviewing agency of the environmental statement will likely be the U.S. Environmental Protection Agency (USEPA). A determination is made as to the appropriate environmental document required, either an Environmental Assessment (EA) or Environmental Impact Statement (EIS).

The EA attempts to evaluate the consequences of a proposed action on the surrounding environment. The assessment should include an evaluation of the existing environment, a determination of the magnitude of the particular change, and the application of a significance or importance factor to the change. It is necessary that the approach used in the assessment be interdisciplinary, systematic, and reproducible. Specifically, the EA should include the following items:

- Description, purpose, and need for the proposed action,
- Alternatives, including a "No Action" alternative,
- Environmental effects of the proposed action and alternatives including:
    - Natural/ecological features (such as flood plains, wetlands, coastal zones, wildlife refuges, and endangered species)
    - Air quality
    - Sound levels
    - Water supply, wastewater treatment, and storm water runoff
    - Energy requirements and conservation
    - Solid waste
    - Transportation
    - Community facilities and services
    - Social and economic factors
    - Historic and aesthetic factors, and
- Listing of agencies and persons consulted in preparation of the assessment.

The EIS is a more rigorous and detailed analysis than an EA although it covers similar topics. The EIS is a document written in the format required by the National Environmental Policy Act (NEPA),

Council on Environmental Quality, and specific agency (i.e., USEPA) guidelines. Two categories of EISs are usually required: draft statements and final statements. The draft statement is usually prepared by the agency proposing the action. This document is circulated for review and comment to other Federal, state, and local agencies, and public and private interest groups. The final EIS compiles and discusses the problems and objections raised by the reviewers.

Air Emissions

The primary pollutants emitted from a new or modified central power plant at the USMA would consist of particulates, sulfur dioxide, nitrogen oxides, carbon monoxide, and volatile organic compounds (hydrocarbons). Smaller quantities of nonvolatile organic compounds and metals would also be emitted.

The New York Department of Environmental Conservation (DEC) has primary review authority for permitting new and modified sources in the area of the USMA. Permits to construct an air pollution source, New Source Performance Standards (NSPS) review, and Prevention of Significant Deterioration (PSD) permitting and National Emission Standards for Hazardous Air Pollutants (NESHAP) regulations are administered by the DEC. The U.S. Environmental Protection Agency Region II has retained full authority to issue or deny PSD permits.

For the NESHAP review, an analysis must show that pollutants regulated under the NESHAP rules are not being emitted in significant quantities. If significant amounts are emitted, those pollutants must be controlled. The regulated pollutants under NESHAP that may be emitted from fossil fuel combustion and their significant levels are shown in Table 10.

In addition to NESHAP pollutants, the USEPA has directed that other toxic pollutants be evaluated for emissions and risk assessment. These pollutants include the following.

Organic vapor:	formaldehyde, phenol, and pyridine,
Organic particulate:	polycyclic organic matter (POM),
Inorganic vapor:	arsenic,* antimony, cadmium, chromium, fluoride,* mercury,* and chlorine,
Inorganic particulate:	arsenic,* antimony, barium, beryllium,* cadmium, chromium, cobalt, copper, lead,* manganese, nickel, phosphorus, radionuclides,* and zinc.

The pollutants may be of concern because of their hazardous, toxic, mutagenic, teratogenic, and/or carcinogenic potential to humans or animals.

In most cases, the quantities of these elements in coals, distillate oils, and natural gases are extremely small or nonexistent. The chemical analysis for the fuel to be used should be examined to determine if any elevated levels of these pollutants exist.

In applying for a PSD permit, a determination of Best Available Control Technology (BACT) must be made. Currently, BACT emission limits must be as stringent as those regulated by New Source Performance Standards under 40 CFR Part 60 Subpart Db for fossil fuel-fired boilers or 40 CFR Part 60

*Regulated under the Clean Air Act.

Table 10

Significant Levels of Regulated Pollutants Under NESHAP

Pollutant	Significant Level (Tons/Yr)
Beryllium	0.0004
Mercury	0.1
Asbestos	0.007
Vinyl Chloride	1.0

Source: 40 CFR Part 61.

Subpart GG for gas turbines. A summary of the air emission standards that would likely apply to the USMA facility is listed in Table 11.

In developing proper emission controls for new boilers, the most stringent Federal or State of New York standards must be applied. The following paragraphs discuss the types of air emission controls that can meet these standards.

Control of Sulfur Dioxide Emissions

Sulfur dioxide emissions from oil combustion will be limited to 0.30 lb SO_2/MBtu by purchasing and firing very low sulfur oil. Additional control of sulfur dioxide emissions is required to meet State of New York and Federal regulations when coal is used as the fuel source.

Current state-of-the-art sulfur dioxide (SO_2) emission control techniques may be divided into three basic methods. These methods include precombustion control, combustion control, and post-combustion control.

Precombustion control consists of either using naturally low sulfur fuels or pretreating the fuel to reduce the sulfur content. Pretreatment of the fuel to remove a portion of the sulfur before combustion is the most economical approach to limiting SO_2 emissions. Coal contains sulfur in both pyritic and organic forms. A substantial portion of pyritic sulfur may be removed by washing the coal. When coal is crushed and passed through a water bath, the pyritic sulfur settles out of the bath since it is usually heavier than the crushed coal. If the coal has a large portion of its sulfur content as pyritic sulfur, washing may remove a large percentage of the original sulfur. Precombustion control (fuel cleaning), however, can only achieve a maximum of about 50 percent sulfur removal for coal, which will not meet emission limitations imposed on new boilers by PSD regulations. Therefore, other methods of control are necessary.

Sulfur dioxide control during the combustion process involves the adsorption of SO_2 in a reactive media inside the combustor. This technique has had considerable success in fluidized bed combustion (FBC) where limestone, dolomite, or other reactive media are used as a bed material and coal is injected into the bed. Limestone is calcined to lime during the combustion process. Sulfur dioxide then reacts with the lime within the combustion chamber.

Post-combustion controls primarily involve the chemical removal of SO_2 from the flue gas using scrubbing reagents. This type of SO_2 emission control is called flue gas desulfurization (FGD).

Table 11

Emission Standards for Fossil Fuel-Fired Boilers[a]

Emission	Coal[b,c]	Oil[c]	Natural Gas[c]
Suspended Particulates	0.05	0.10	NS[d]
Sulfur Dioxide	1.20[e]	0.30[f]	NS
Nitrogen Oxides	0.60	0.20[g]	0.20[g]
Carbon Monoxide	NS	NS	NS
Volatile Organic Compounds	NS	NS	NS
Lead	NS	NS	NS

[a] Source: 40 CFR, Part 60, Subpart Db, Standards of Performance for New Stationary Sources; Industrial-Commercial-Institutional Steam Generating Units. Values in lb/MBtu.
[b] Coal derived synthetic fuels including, but not limited to, solvent refined coal, gasified coal, coal-oil mixtures, and coal-water mixtures are included in the definition of coal.
[c] If Prevention of Significant Deterioration permitting is applicable, emission limitations for all pollutants listed below will probably be less than the values shown.
[d] NS = No Standard.
[e] Value shown is maximum emissions. Ninety percent SO_2 removal is also required.
[f] Equivalent to oil with a heating value of 140,000 Btu/gallon and containing 0.3 percent sulfur.
[g] Based on high heat release rate. The limit is 0.1 lb/MBtu based on low heat release rate.

Systems designed to remove the SO_2 from flue gas have become widely used. More than a dozen processes have been commercialized with new processes continuing to be developed. FGD processes can be divided into two major categories, wet and dry systems, which can be further categorized as regenerative and nonregenerative types. Wet regenerative processes result in an end product that is potentially saleable, usually elemental sulfur or sulfuric acid, while recovering and recycling the reagent material. Wet and dry nonregenerative processes use the reagent material only once, producing a waste product that usually has little or no commercial value and must be disposed of in ponds or landfills.

Regenerative processes require a chemical processing plant to isolate and purify the saleable byproduct. These processes are capital intensive and economical only in large-scale applications and are, therefore, not appropriate for the USMA. Consequently, only nonregenerative processes were considered.

The lime spray-dry FGD system was selected for the spreader stoker alternatives over other nonregenerative FGD systems and, in particular, wet lime FGD scrubbing, for the following reasons:

- Spray-dry FGD systems produce a dry, solid waste product consisting of a mixture of unused reagent, waste products, and fly ash.
- The dry solid waste product produced can be handled by conventional fly ash handling equipment thus eliminating thickening, dewatering, and stabilization facilities necessary to process the sludge from a wet FGD system. Consequently, less area is required for a spray dry type FGD system. Space for sludge treatment facilities is not available at the USMA.
- The pumping costs are lower.
- The system experiences overall improvement in operation including rapid response to changes in inlet SO_2 and flue gas flow rate.

- The system has higher reliability and lower maintenance requirements.
- The system has lower energy requirements (typically 50 percent of wet FGD scrubbing systems) and reheat requirements are usually eliminated.
- The system has significantly lower capital costs.

The waste material produced by an FBC type boiler is similar to the waste products from a spray-dry FGD system.

Either the fluidized bed combustor or the flue gas desulfurization system will remove enough SO_2 to meet the emission limit of 1.2 lb of sulfur dioxide/MBtu heat input and 90 percent removal limitation imposed by NSPS regulations. Removal of at least 90 percent SO_2 will also be necessary to provide sufficient reduction in emissions to meet BACT standards for coal-fired boilers. Installation of new gas, No. 2 oil-fired boilers will not require the use of an FGD system to meet emission regulations as long as very low sulfur oil is used.

Control of Particulate Emissions

Particulate control technology is limited to three types of control systems. These systems include mechanical collectors (MC), which include venturi scrubbers, electrostatic precipitators (ESP), and fabric filters (baghouses).

Mechanical collectors come in many sizes and types and use centrifugal force to remove the larger particulates from the flue gas stream. The collection efficiency of an MC is directly proportional to the pressure drop across the collector. Therefore, high collection efficiencies can be obtained only with high operating costs in the form of increased fan horsepower requirements. The use of mechanical collectors is not a feasible control technology since an MC cannot achieve the degree of particulate removal required for the USMA.

Electrostatic precipitators use a different technique to remove particulates from the flue gas stream. Inside the ESP, a large electric potential of several thousand volts is built up between wires or rods and collection plates. As the flue gas passes through the ESP, the particles become charged and migrate to the collection plates. The plates are periodically rapped to drop the collected particulates into receiving hoppers. The collection efficiency of the ESP is a function of the migration velocity of the particles and the ability of the particles to become electrically charged. If the resistivity of the ash particles is high, the particles do not become electrically charged easily, and the overall efficiency of the ESP is reduced. Fly ash resistivity generally increases as the quantity of SO_2 in the flue gas decreases. Therefore, ESPs for use on lower sulfur coals or FBC boilers tend to be larger than their counterparts designed for use on higher sulfur coal.

Baghouses capture particulates by a filtration process. A series of modules are constructed, each of which contains filter bags. The bags may be made from a variety of materials but high temperature-resistant materials such as fiberglass and teflon are generally used for coal-fired boilers. The exact bag material depends on the operating conditions of the collector. Baghouses tend to have a high collection efficiency over a wide range of operating conditions. Collection efficiency is independent of sulfur content of the fuel.

All baghouses operate by ducting dirty gas to the unit where it is filtered by cloth tubes or bags. The filtering is extremely efficient and normally results in better than 99 percent removal of entrained particles. The bags must be periodically purged of the collected material. The method and frequency of cleaning characterizes one type of baghouse from another. These methods include shaking the bags,

rapidly expanding the bags by a pulse of compressed air, or reversing the direction of air flow through the bags.

The bags in shaker-type baghouses are supported by a structural framework that is free to oscillate when driven by a small electric motor. Dampers isolate a compartment of the shaker-type baghouse so that no air flow occurs. The bags in the compartment are then shaken for approximately 1 minute. The collected dust cake is dislodged from the bags and falls into a hopper for removal. The dampers then open, allowing the section to go back on-line.

Reverse pulse baghouses have been increasingly used in recent years. This design uses a short pulse of compressed air through a venturi, directed from the top to the bottom of the bag. This primary pulse of air aspirates secondary air as it passes through the venturi. The resulting air mass violently expands the bag and casts off the collected dust cake.

Timer controlled dampers isolate the compartments in a reverse flow type baghouse. An auxiliary fan damper is then opened, forcing air through the bags in the direction opposite to filtration. This backflow action collapses the bag and fractures the dust cake allowing it to drop into hoppers. When the bag is brought back on-line and reinflated, more of the fractured dust cake is dislodged into the hopper. This procedure may be repeated several times during the 2- or 3-minute cleaning cycle.

The reverse pulse and reverse flow baghouses have received the widest acceptance for coal-fired institutional or industrial-sized boilers.

Many considerations are reviewed during baghouse design. Filter life and efficiency are influenced by cleaning procedures since, for example, a heavy deposit may put undue stress on the fabric and frequent agitation may lead to early rupture. Filter life is also influenced by contaminant properties; for instance, hygroscopic or extremely fine particles may result in permanent plugging or blinding of the bags.

Air-to-cloth ratio (A/C) is an important design variable and may be specified for three modes of operation for a modular-type reverse flow fabric filter: Gross A/C (all modules in service); Net A/C (one module in a cleaning cycle including reverse air flow); and Maintenance A/C (one module out of service plus one module in a cleaning cycle including reverse air flow). Net air-to-cloth ratios of 4 to 6 are common for pulse baghouses, while reverse air baghouses are normally designed for a net A/C of about 2.

Filter costs depend primarily on size, which is greatly influenced by flow rate. Low velocities require large filter areas and corresponding high initial expense. On the other hand, high velocities are accompanied by greater pressure drops and high operating and maintenance costs.

For spreader stoker-fired boilers, a spray-dry FGD system with a baghouse is recommended to control sulfur dioxide and particulate emissions. When spray-dry FGD systems are used, a significant portion of the sulfur dioxide removal occurs in the particulate control baghouse as SO_2 continues to react with excess lime in the system. This can account for 20 to 25 percent of the total SO_2 removed.

For fluidized bed combustors, a baghouse should also be used for particulate emission control. FBC systems have very high rates of uncontrolled particulate emissions compared to other coal-firing techniques such as pulverized or stoker firing. Although other types of particulate control equipment, such as ESPs, have been successfully applied to FBCs, baghouses have received wide commercial acceptance. A reverse pulse baghouse, with a collection efficiency of 99.8 percent, should be used with either a spreader stoker-fired boiler or a fluidized bed combustor.

Boilers operating on natural gas or on most fuel oils do not require particulate emission controls.

Control of Nitrogen Oxide Emissions

Current technology for control of nitrogen oxides (NO_x) in fossil fuel boilers is rapidly changing. Two basic NO_x control strategies presently exist. The first strategy is to control the formation of NO_x during the combustion process. The greater portion of emitted NO_x originates from the reaction of nitrogen (N_2) and oxygen (O_2) at high temperatures during combustion. Consequently, the procedure for minimizing NO_x during combustion generally involves reducing excess O_2 available for combustion and reducing high combustion temperatures. This is generally achieved using a staged-combustion technique where a fuel rich primary combustion region is created with a secondary combustion region to provide total fuel combustion.

The second NO_x control strategy involves using post-combustion NO_x removal systems. Although many techniques have been tested, the method that holds the most promise for coal-fired boilers is selective-catalytic reduction (SCR). This process converts NO_x back to N_2 and O_2 using ammonia in the presence of a catalyst. SCR has shown significant NO_x emission reductions on oil and gas-fired boilers but the technology for coal-fired boilers is just emerging. This technique may be required where high NO_x reduction is required; however, the high capital costs and operating expenses tend to offset any advantages where in-boiler NO_x controls may be used.

The fluidized bed combustion process controls NO_x emissions by maintaining low combustion temperatures; between 1500 to 1600 °F. This is accomplished by using a bed of inert ballast such as sand and limestone or dolomite pellets. The bed is fluidized by passing combustion air through it at a velocity determined by the operating characteristics of the process. The bed offers excellent heat transfer capabilities, resulting in lower combustion temperatures.

Regulations require that NO_x emissions be limited to no more than 0.6 lb/MBtu heat input for solid fuels and 0.1 to 0.2 lb/MBtu heat input for liquid fuels. These limitations can be met by either well designed spreader stoker units, fluidized bed combustors, or units burning oil or natural gas.

Typical NO_x emission rates from a spreader-stoker boiler using proper combustion techniques would be 0.6 lb NO_x/MBtu or less. For fluidized bed combustors, emissions would be 0.4 lb NO_x/MBtu or less.

Selective catalytic reduction equipment has been included for all plans using natural gas and No. 2 fuel oil to control nitrogen oxides emissions. Emissions of NO_x will be limited to 10 parts per million, if required.

Visible Emissions

Scattering aerosol particles, mainly in the range of 0.1 to 1.0 micron in diameter, can result in visible emissions from the boiler's stack. The visual effect of such particles can be complicated by local weather conditions such as rain, fog, snow, and humidity. Because particles larger than 1.0 micron do not scatter light as do smaller particles, they have little effect on visibility.

The State of New York regulations governing visible emissions impose a limit of 20 percent opacity on a continuous basis. However, the NSPS regulations do allow emissions up to 27 percent opacity for a period of not more than 6 minutes in any 60-minute period. Emissions in excess of 20 percent opacity are allowed only during startup and emergency situations if these emissions are not preventable.

Particles resulting from coal combustion are primarily fly ash and secondary aerosols derived from SO_2. Installing a 99.8 percent efficient particulate removal system is expected to reduce visible emissions to less than 10 percent opacity, which would meet NSPS and the State of New York opacity standards.

Fugitive Emissions

Fugitive emissions are defined as those emissions not normally emitted through a primary exhaust system such as a stack, flue, or emission control system. The types of fugitive emissions of concern are from storage and handling of coal before combustion, and handling and disposal of ash and FGD wastes for all coal-fired boiler alternatives.

Several aspects of coal dust fugitive emissions should be considered during the air quality permitting process. Fugitive emissions of coal dust may result from:

- Transport of coal to the facility,
- Coal unloading operations such as dumping to an unloading hopper and conveying to storage,
- Open storage piles, and
- Load out and conveying from storage to coal bunkers.

Several methods are available to reduce fugitive emissions. Coal dust suppression procedures for minimizing fugitive emissions during transport include covering coal trucks and/or spraying with dust suppressant surfactants. Dust suppression procedures for unloading operations include unloading coal in an enclosed building with filtered ventilation, vacuum aspirated hoods over the unloading hopper ducted to a fabric filter, or spraying with surfactants during the unloading operation. Enclosed storage silos would eliminate fugitive emissions caused by wind blowing over open storage piles. Procedures to control coal dust from both the loading into storage silos and subsequent loading to surge bins, would include a negative pressure ventilation system with a fabric filter. Collected coal dust would be returned to the conveying system for eventual combustion.

The quantity and characteristics of fugitive emissions generated by a new steam or hot water generating facility will depend on the final type and size of the units and the fuel used.

Solid Wastes

Solid wastes generated by coal combustion consist of ash (fly ash and bottom ash) and waste products from the sulfur dioxide removal process. The waste products include calcium sulfite, calcium sulfate, and unreacted lime from the spray-dry FGD system used with the spreader-stoker fired boiler option. The waste products from a fluidized bed combustor consist of calcium sulfate, lime, and limestone. For both alternatives, the fly ash and a portion of the FGD waste are intimately mixed in the flue gas stream. These wastes are removed from the flue gas by the baghouse. Bottom ash from both spreader stoker and FBC units would be blended with the fly ash and FGD waste before disposal.

The quantity of waste generated depends on the ash and sulfur content of the coal as well as the percentage of SO_2 removed. As the SO_2 removal efficiency increases, the amount of waste produced also increases. The excess reagent to waste increases disproportionately due to the lower efficiency of the FGD process at higher SO_2 removal rates.

The solid waste produced is a dry, flowable powder with less than 5 percent moisture. The material can be handled and transported easily. Interim storage of waste on site would be required. This would

consist of a silo sized to hold at least 3 days of waste production at maximum plant operating rates. The waste material would be transported off the site by truck.

The value of the combustion residue as a construction material is limited. Fly ash is commonly used in concrete as a filler material and gypsum (calcium sulfate) produced in wet FGD scrubbers has been used in manufacturing wallboard. Because the waste material from both FBCs and dry FGD systems is a blend of fly ash, reaction products, and unused reagent of varying quality, it is unsuitable for these uses. Landfilling the waste generated or contracting with the coal supplier to return the wastes to the coal mine are the only practical methods of disposal.

Coal combustion residue currently is classified by the USEPA as a nonhazardous waste. As a non-hazardous waste, coal combustion byproducts generally can be disposed of in conventional sanitary landfills in accordance with local regulations. The regulations governing operation and construction of landfills in the State of New York are contained in Article 27 of the New York Solid Waste Management Law.

Landfills near major cities are rapidly disappearing as existing landfills are filled to capacity. Disposal costs have escalated dramatically in recent years due to increasingly strict environmental regulations and the lack of land available for new landfills. Disposal costs are expected to continue to escalate.

An alternative to landfilling is to return the coal combustion wastes to the coal mine for disposal. Several coal suppliers recently contacted indicated a willingness to participate in such an arrangement and that they possessed the necessary licenses and permits to do so. The waste material would be hauled by truck on the return trip to the mine after a coal delivery, thus minimizing transportation costs. All coal-fired boiler plans include this alternative of returning coal combustion wastes to the coal mine for disposal. Use of distillate fuel oil or natural gas will eliminate the concerns of solid waste disposal.

Liquid Wastes

Liquid wastes generated from the handling and combustion of fossil fuels usually consist of runoff from coal storage piles, boiler blowdown, and cooling water.

Runoff from coal storage will be a concern for the plans involving spreader stoker and FBC systems. Any runoff water, specifically rain and dust suppression water, would be collected and treated before discharge. Use of fuel oil or natural gas would not require these precautions.

Boiler blowdown is the removal of concentrated boiler water from the boiler system. The purpose of boiler blowdown is to maintain the solids content of the boiler water within acceptable limits to prevent corrosion and scaling of boiler heat transfer surfaces. Blowdown typically contains concentrated sodium salts present in the makeup water and boiler internal treatment chemicals such as amines, phosphates, and sodium sulfite. Boiler blowdown is usually cooled and discharged to a sanitary sewer for treatment.

Potable water used for once-through cooling of equipment may be discharged directly to a storm sewer system as long as it does not become contaminated in the process.

6 ENVIRONMENTAL IMPACT

Air Quality Trends

Statewide levels of regulated pollutants have been decreasing in the past 10 years in New York, although some areas still fail to meet the National Ambient Air Quality Standards (NAAQS). The West Point area is classified as "attainment" for all NAAQS except for ozone. The entire metropolitan area of New York is classified as "nonattainment" for ozone. Since nitrogen oxides have been identified as a possible precursor to ozone formation, nitrogen oxides emissions may fall under the Department of Environmental Conservation nonattainment regulations if emissions exceed 100 tons per year. It is not expected that this area will come into compliance in the next few years.

To maintain existing air quality levels, new sources of pollutants will be given a stringent review and will be required to meet New Source Performance Standards or Best Available Control Technology. Quantification and control of particulate matter with a size less than 10 microns will also be required. A new particulate standard for particulates under 10 micrograms was promulgated in 1987 and must be addressed for the permitting of new particulate-emitting sources.

Health Effects

The addition of a coal-fired system will have a measurable, although minimal, effect on the air quality of the area. Increases in particulates, sulfur dioxide, nitrogen oxides, carbon monoxide, and trace metals may not be offset by eliminating oil-firing at the existing plant. The new plant will be required to control emissions significantly, thus reducing the possibility of exceeding an ambient standard or pollutant increment limitation. Analyses of quantities and health effects of trace metals and toxic emissions will be required. The health effects of these additional pollutants are also expected to be minimal. For oil or natural gas combustion, the health impacts should be no greater than those occurring with the existing oil firing.

Noise and Transportation

Total noise levels should increase only slightly from existing levels if steam or hot water boilers are installed at a new location. Noise from the boilers and appurtenances will be restricted by building enclosures.

The equipment associated with the various coal-fired boiler alternatives discussed in this report, including coal and ash handling systems, would not produce appreciably higher noise levels than the existing fans, pumps, and other equipment installed in the Central Power Plant. Noisy equipment would be shielded by building enclosures and can be sound insulated to keep interior sound levels at or below an 85 to 90 decibels, a-weighted (dBA) level.

Most noticeable noise increases will come from the increased truck traffic necessary to transport fuel to and wastes away from the facility if any of the coal-fired boiler plans are adopted. The number of trucks required for FBC or spreader stoker systems is estimated to be only one or two per hour.

The increase in noise levels is expected to be minimal on a long-term average; instantaneous noise levels will be considerably higher with the passage of a truck. However, due to the small number of truck

trips per hour, the long-term increase in noise levels from the increased truck traffic will most likely not be detectable to the average person.

Transportation patterns will change very little with the addition of a coal-fired power plant. The estimated increase in truck traffic will produce minimal impact on traffic congestion, road surface deterioration, and noise levels along the access routes.

Visual Impact

The present central power plant is a relatively tall building with a very short, integral stack. This stack is barely recognizable as a stack. The plant appearance will not change significantly if new gas/oil-fired boilers or coal water-fired boilers are installed.

New coal-fired units, whether spreader stoker or FBC, would be housed in tall, enclosed structures at a new site. The stacks required for these plants would be mounted on the baghouse structure and would be much taller and more visible. Good engineering practice requires tall stacks to avoid exhaust plume downwash. The waste material, coal, and limestone or lime silos could be left exposed or, if necessary, various architectural facades could be used to shield them.

Four sites were considered for locating a new thermal and electric generating facility as shown in Figure 1. Construction of a new facility at Site 3, currently Parking Lot E, would have the greatest visual impact since this site is visible from much of the campus. Site 2 is centrally located on the USMA grounds and would have relatively little visual impact. Site 1 near Washington Gate is presently occupied by the Motor Pool and parking for recreation vehicles. This location is in a well developed area of the campus and includes other industrial facilities such as the laundry and storage buildings. Site 1 is also judged to have minimal visual impact since the area is already classified as industrial. However, stacks for any new power plant on this site may be visible from the plain. A fourth potential site would be located adjacent to Highway 293 approximately 1/2 mile southwest of the intersection of Highways 293 and 9W. This location is off-campus and would, therefore, have no visual impact with regard to the campus.

Oil/gas-fired boilers would require a smaller building and shorter stacks, thus, reducing the visible impact. No coal or limestone storage would be required.

Thermal Impact

Thermal impact on both the air and water resources will be minimal for any of the alternate plans considered. The full load design stack temperature for the gas/oil-fired boilers is estimated to be 250 °F. Stack temperatures for fluidized bed combustors are approximately 100 degrees higher (350 °F) than for gas and oil firing. Spreader stoker stack temperatures may be as low as 150 °F. This low temperature is a result of the large quantities of water evaporated in the FGD process. These temperature differences should affect only the air in the immediate vicinity of the plume, producing a minimal change from existing conditions.

Thermal impact on water quality should be similar to existing conditions. Water temperature and water quantities discharged should be the same as current levels.

Land Use

From a general perspective, the Central Power Plant would remain in its present location for those two plans that refurbish the steam electric generating facilities, so major land use relationships would remain the same. All equipment changes would be within Building 604.

For any plan using Site 1, it is estimated that 9 acres would be required for the power plant, fuel storage, roads, and parking areas. Land use would change from parking to power generation. Work on an access road would be required along with trenching for routing of steam, condensate, and in some cases, chilled water piping.

Site 2 occupies approximately 4 1/2 acres. Since the available land area at Site 2 is only about one-half of that available at Sites 1, 3, and 4 (4 1/2 acres available versus 9 acres), ground storage of coal would not be possible for a coal-fired central heating plant at Site 2. Instead, coal would be stored in six coal silos, each with a capacity of about 2000 tons. Land use would change from woodlands to power generation. Access roadways would be added as well as trenches for routing of steam, condensate, and for certain plans, chilled water piping.

Site 3 is currently occupied by Parking Lot E. The area required for the new Central Power Plant and all associated equipment is estimated to be 9 acres. New access roads would be required as well as trenches for routing steam, condensate, and chilled water piping.

Site 4, located approximately 1 1/2 miles beyond Site 1, is approximately 1/2 mile southwest of the intersection of Highways 293 and 9W. Approximately 9 acres would be required for this site. New access roads would be required as well as trenches for routing steam, condensate, chiller water, and sewer piping. Also, overhead and underground (or both) electric power lines would be required. This site might also require relocating a portion of the golf course, depending on the exact site selected.

7 FEASIBILITY ANALYSIS

This chapter compares the costs associated with the alternative plans; the more attractive plans are identified. As required by USMA, the various plans are compared using the Life Cycle Cost In Design economic analysis computer program created by USACERL (Lawrie 1988) and tailored to the needs of the Department of Defense (DOD). This program calculates the life cycle costs associated with construction projects and incorporates the economic criteria used by the Army. The procedure makes comparisons between the total discounted costs associated with each project over its life cycle by reducing all costs to their present value as of the analysis date, discounting at 10 percent per year, the rate specified by DOD. The analysis assumes that the economic life of the various alternatives considered will be 25 years and is conducted in terms of constant dollars as of the date of the analysis. However, differential energy escalation rates over the period of analysis are used as specified by the U.S. Department of Energy for different fuels.

The analysis assumes that construction costs for the various alternatives will be incurred at the midpoint of construction and that annual cash outflows will occur at the midpoint of each year.

The LCCID method of analysis includes all energy requirements and cost factors for each plan, whether cogeneration or non-cogeneration, which allows each plan to be compared directly to any other plan, both technically and economically.

As specified in the scope of this project, the LCCID analysis was performed only for the 12 most attractive plans as determined by an initial screening analysis. This screening was required to develop certain input data required by the LCCID program.

Projected Electrical and Fuel Costs

For each of the alternative plans described in Chapter 4, calculations were made of USMA's monthly electrical use and fuel use (by type) with the particular configuration of equipment. These required electrical and fuel inputs were costed at 1990 prices and subsequently escalated into the future using the rates specified by LCCID.

Electrical costs were calculated using the charges specified in USMA's special contract with Orange and Rockland Utilities.* This contract has a demand charge per kW with a higher charge in summer months than in nonsummer months, a declining-block energy charge with higher charges per kWh for the first 300 hours use of demand than for subsequent kWh use, and an energy cost adjustment.

Natural gas costs were calculated using the charges specified in USMA's special contract with Central Hudson Gas & Electric Company.** The contract gas rates reflect a declining-block rate structure with a seasonal differential (higher charges in winter months) for use above 2500 thousand cubic feet (MCF) and a purchased gas adjustment. The monthly billing calculation also reflects a revenue tax adjustment applicable to the first 2500 MCF.

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* Full details are included in "Appendix F, Utility Contracts and Rates," of the unpublished report *Preliminary Report on Energy Supply Alternatives for the Year 2002 at USMA* (Stanley Consultants, November 1990).

** Although SCI was unable to obtain a copy of this contract, the charges it specifies are detailed in "Appendix F, Utility Contracts and Rates," of the unpublished report *Preliminary Report on Energy Supply Alternatives for the Year 2002 at USMA*, Stanley Consultants, November 1990.

Oil, coal, and coal/water costs were calculated using current costs as they would be incurred by USMA.

Plant Efficiencies

Two methods were used to compute plant efficiencies for the four top ranked cogeneration plans. The first method determines the true plant thermal-electrical efficiency. The second method is prescribed by the Public Utility Regulatory Policy Act (PURPA), which requires the electric utility to provide supplementary power, back-up power, maintenance power, and interruptible power to the qualifying cogenerating facility.

Plant Efficiency

Plant efficiency is the electricity and steam produced by the plant (in millions of Btus) divided by the total fuel input to the system in millions of Btus, including both the generating plant and supplemental firing.

PURPA Efficiency

The PURPA efficiency is the total of the electricity plus one-half of the steam produced by the plant (all converted to millions of Btus) divided by the total fuel input to the system in High Heating Value converted to million Btus times 0.9. PURPA efficiency of the qualifying cogenerator must be at least 42.5 percent.

Results of these computations are summarized below, ranked from highest to lowest efficiency. All of these cogeneration plans comply with PURPA requirements.

Plan	Plant Efficiency, Percent	PURPA Efficiency, Percent
11A	89.3	59.9
13A	88.1	59.2
12A	85.4	57.4
1A	80.8	50.7

Capital Investments

Capital cost estimates are current as of July 1990 and have been prepared to an accuracy of ±25 percent. The feasibility analysis presented here assumes the use of Site 1, which has the lowest site-related costs of $259,000.* In the overall comparison, costs for Sites 2 and 3 ($388,000 and $328,000, respectively) are little different from Site 1. Site 4 costs, which depend on the plan selected but total about $23 million, are significantly greater than those for the other sites. The only advantages of Site 4 are aesthetic; the site is not visible from the USMA campus.

This analysis assumes continued use of the existing steam distribution system. Repairs and replacements of leaking portions of the system should be completed as soon as possible. Leaking condensate lines and direct burial conduits cannot wait 10 years to be repaired or replaced at the time a

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* The capital investments required for the alternative plans analyzed are specified in detail in "Appendix B, Project Cost Estimate," of the unpublished report *Preliminary Report on Energy Supply Alternatives for the Year 2002 at USMA*, (Stanley Consultants, November 1990).

new power plant is constructed. A new steam distribution system would cost about $24.6 million, but would provide few additional benefits at the time a new power plant is constructed.

Operating Costs

Operating costs for the various alternatives (other than electric and fuel costs) are of two types: regular annual operation and maintenance costs and major overhaul costs. While all equipment requires annual maintenance, certain types of equipment, especially that used in cogeneration plans, require major overhaul every 4 or 5 years. For these plans, an appropriate allowance has been made for major overhauls.

For coal-based plans, operating costs include costs associated with lime or limestone, scrubber material, and ash-handling.

Initial Screening

Four different computer models were prepared for the screening analysis. These are described briefly below.* All models calculate the present value of the cost to USMA of meeting heating and cooling loads over the 25-year expected life of the new equipment. This result is then expressed as an equivalent annual cost. The four models used are:

1. The Refurbishing Model in which USMA's existing cogeneration facilities are refurbished.

2. The Non-Cogeneration Model in which USMA's new facilities are assumed to not include cogeneration equipment. All electricity used is purchased from Orange and Rockland Utilities.

3. The Cogeneration Model in which USMA's facilities include new cogeneration equipment. In these plans, a portion of the electrical energy used is generated and a portion is purchased from Orange and Rockland Utilities.

4. The Third-Party Financing Cogeneration Model in which a third-party constructs and operates the new facilities. The third-party then sells steam and, for plans with central chilled water systems, chilled water to USMA and sells electricity, as a qualifying cogenerator/independent power producer, to Orange and Rockland Utilities.

All four models use, as input variables, the capital costs of the new equipment and its annual operation and maintenance costs in 1990 dollars. They also use 1990 charges from USMA electricity and gas supply contracts, and 1990 costs of other fuel and related inputs. These costs are escalated at rates specified by the U.S. Department of Energy and incorporated in the LCCID analysis.

The cogeneration models make assumptions about the manner of operation of cogeneration facilities, and hence about USMA's purchases of power from Orange and Rockland Utilities. The third-party financing cogeneration model assumes that all electricity requirements will be met by Orange and Rockland Utilities, and that all electric output of the third-party developer will be sold to Orange and Rockland at 6 cents per kWh in 1990, escalating at the same rate as Orange and Rockland's other rates.

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* More detail, including examples of the output, are in "Appendix C, Screening Analysis Computer Model," of the unpublished report *Preliminary Report on Energy Supply Alternatives for the Year 2002 at USMA*, (Stanley Consultants, November 1990).

Note that this model assumes that the third-party developer buys natural gas from Central Hudson Gas & Electric Co. at its regular commercial rate, which has charges significantly higher than those of the USMA gas supply contract.

The results are summarized in Tables 12, 13, 14, and 15.* These tables show, in order, results for refurbishing plans; non-cogeneration plans; new cogeneration plans; and third-party financed cogeneration plans. Each table shows, for each plan in 1990 dollars, its capital investment and its annual operating costs including expenses for electricity, other fuels, and other operation and maintenance costs, together with the equivalent annual costs for the plan over the 25-year planning horizon from 2001 through 2025.

Among the refurbishing plans, Table 12 shows that the capital investment costs associated with the gas/oil-fired boilers of Plan 1 are substantially lower than the capital costs of the coal/water-fired boilers of Plan 2. Further, the annual operating expenses associated with Plan 1, including fuel costs, are also lower than those of Plan 2. Finally, for both Plan 1 and Plan 2, not only are the capital investment costs of the E option (installing new absorption chillers) greater than the investment costs of the A option (continued use of existing chillers), but the annual costs are also greater. The table shows that although the E option shows savings in electricity purchase costs compared to the A option, these are outweighed by higher fuel purchase costs and by slightly greater operation and maintenance costs. In terms of the measure used for ranking (25-year equivalent annual costs), the table shows that Plan 1A is the lowest cost of the four plans followed, in order, by Plans 1E,

Among the non-cogeneration plans, Table 13 shows that the capital investment costs associated with the gas/oil-fired boilers of Plan 3 (Central Steam Heat) and Plan 5 (Central Hot Water Heat) are substantially lower than those associated with the coal-fired boilers of Plan 4 (Central Steam Heat) or Plan 6 (Central Hot Water Heat). These costs range from $29.3 million for Plan 3A (Central Gas/Oil-Fired Steam Heat with Existing Chillers) to $109.8 million for Plan 6C (Central Stoker Coal-Fired Hot Water Heat with a New Central Chilled Water Plant with Centrifugal Chillers). The annual costs for electricity, gas, oil, and other operation and maintenance costs fall in a fairly narrow range for all of these plans, except Plan 16D (All Electric Energy with Centrifugal Chillers) for which the annual costs are $15.6 million. As a result, the 25-year equivalent annual costs of these non-cogeneration plans range from $15.1 million for Plan 3A (Central Gas/Oil-Fired Steam Heat with Existing Chillers) to $24.6 million for Plan 16D (All Electric Energy with Existing Absorption Chillers Replaced with Centrifugal).

Among the new cogeneration plans, Table 14 shows that the capital investment costs associated with the coal-fired plans (Plan 10) range from $85 million to $117 million, depending on the chilling option selected, and are substantially greater than the investment costs of the gas and oil/gas plans (Plans 9, 11, 12, and 13) which range from $40 million to $68 million. Since the annual costs of all plans are in a fairly narrow range from $8.3 million to $9.8 million, the 25-year equivalent annual costs of the coal-fired cogeneration plans, ranging from $19.1 million to $23.0 million, tend to be greater than those using gas and gas/oil, which range from $15.4 million to $20.7 million, depending on the chilling plan selected.

* The results of the screening analysis are presented in each plan's computer output in "Appendix D, Results of Screening Analysis; Refurbishing Plans and Non-Cogeneration Plans; New Cogeneration Plans, and Third-Party Financing Cogeneration Plans," of the unpublished report *Preliminary Report on Energy Supply Alternatives for the Year 2002 at USMA*, Stanley Consultants, November 1990.

Table 12

Summary of Refurbishing Plans

Plan	Capital Costs (in $1000s)	Expenses (in $1000s) Electric	Fuel	O&M	Total	25-year Equivalent Annual Cost (in $1000s)
1A	19,959	3,209	3,971	1,489	8,669	13,463
1E	31,154	2,974	4,572	1,498	9,044	15,400
2A	51,128	3,209	3,525	2,754	9,488	16,532
2E	62,323	2,974	4,115	2,817	9,906	18,327

Table 13

Summary of Non-Cogeneration Plans

Plan	Capital Costs (in $1000s)	Expenses (in $1000s) Electric	Fuel	O&M	Total	25-year Equivalent Annual Cost (in $1000s)
3A	29,286	4,722	3,307	1,482	9,511	15,058
3C	53,422	4,767	2,994	1,740	9,501	17,529
3D	36,350	4,885	2,994	1,475	9,354	15,510
4A	73,721	4,722	1,764	3,288	9,774	18,748
4C	97,857	4,767	1,569	3,519	9,855	21,438
4D	80,785	4,885	1,569	3,254	9.708	19,419
4AA*	83,026	4,722	1,723	3,379	9,824	19,811
4CC*	107,162	4,767	1,533	3,770	10,070	22,668
4DD*	90,090	4,885	1,533	3,505	9,923	20,649
5A	44,818	4,722	3,307	1,870	9,899	17,157
5C	68,954	4,767	2,994	2,128	9,889	19,629
5D	51,882	4,885	2,994	1,863	9,742	17,609
6A	85,644	4,722	1,764	3,586	10,072	20,362
6C	109,800	4,767	1,569	3,818	10,154	23,052
6D	92,728	4,885	1,569	3,552	10,006	21,033
16D	71,553	14,395	0	1,161	15,556	24,554

*Plan number with double letters indicates that the coal burning technology for that plan is fluidized bed combustion.

Table 14

Summary of New Cogeneration Plans

Plan	Capital Costs (in $1000s)	Expenses (in $1000s) Electric	Fuel	O&M	Total	25-year Equivalent Annual Cost (in $1000s)
9A	40,086	1,458	6,089	1,936	9,483	17,595
9B	63,874	1,258	6,349	2,187	9,794	20,661
9E	51,281	1,258	6,479	1,945	9,682	19,236
10A	84,888	1,458	3,273	3,961	8,692	19,060
10B	108,676	1,258	3,436	4,234	8,928	21,946
10E	96,083	1,258	3,516	4,004	8,778	20,431
10AA*	93,225	1,458	3,197	4,208	8,863	20,129
10BB*	117,013	1,258	3,356	4,484	9,098	23,012
10EE*	104,420	1,258	3,435	4,254	8,947	21,496
11A	41,995	1,629	4,488	2,203	8,320	15,406
11B	65,783	1,412	4,881	2,454	8,747	18,663
11E	53,190	1,412	5,059	2,212	8,683	17,315
12A	42,447	1,655	4,750	2,025	8,430	15,877
12B	66,235	1,440	5,293	2,276	9,009	19,373
12E	53,642	1,440	5,513	2,034	8,987	18,090
13A	43,958	1,623	4,408	2,452	8,483	15,522
13B	67,746	1,413	4,817	2,703	8,933	18,813
13E	55,153	1,413	4,983	2,461	8,857	17,445

*Plan number with double letters indicates that the coal burning technology for that plan is fluidized bed combustion.

The costs for the third-party cogeneration plans are summarized in Table 15. This table shows the capital investment required to be made by the third-party, the annual costs incurred by USMA for electricity, for steam and, where applicable, for chilled water, and the 25-year equivalent annual costs for USMA. Generally, the third-party plans do not look very attractive for USMA for several reasons. First, the capital investment required for the third-party financing plans is from $69 million to $116 million, depending on the chilling plan selected. This is significantly greater than that required for the equivalent gas turbine cogeneration cases where the capital investment ranges from $42 million to $66 million. Second, the third-party is assumed to have a required return of 18 percent per year on its investment, whereas USMA has an assumed cost of capital of 10 percent. Third, the third-party's revenue requirement on its sales of steam and electricity includes income taxes on any profits earned in the transactions. This is a component of cost that is not present in the other cases. Fourth, and probably most important, the third-party's purchases of gas from Central Hudson Gas and Electric Co. are at Central Hudson's general commercial rate, which has a tail-block charge applicable to most purchases of about $1.40 per MCF or 50 percent higher than the tail-block charge of the USMA contract.

Table 15

Summary of Third-Party Financing Cogeneration Plans

Plan	Capital Costs (in $1000s)	USMA Expenses (in $1000s) Electric	Steam and Chilled Water	Total	USMA 25-year Equivalent Annual Cost (in $1000s)
14A	69,007	4,722	18,880	23,602	34,863
14B	92,795	4,487	23,221	27,707	41,456
14E	80,202	4,487	20,989	25,476	37,936
15A	92,409	4,722	21,873	26,595	39,584
15B	116,197	4,487	26,290	30,777	46,296
15E	103,604	4,487	24,128	28,615	42,887

Table 15 shows that the 25-year equivalent annual cost for USMA for the third-party financing cogeneration plans ranges from $34.9 million to $46.3 million. This range is significantly higher than the equivalent annual costs for any of the other plans.

These costs may, in fact, be slightly overstated. The third-party financing analysis assumes that all investment costs associated with the plans are incurred by the third-party and that the third-party's revenue requirements associated with these investments (other than those recovered from sales of electricity) are paid by USMA through charges for steam and, where applicable, chilled water. In fact, only 70 percent to 90 percent of investment costs are incurred by the third-party. The remainder are incurred by USMA as investments in distributed chillers, electrical switchgear, steam distribution, chilled water distribution, or other equipment. Since USMA's capital costs are assumed to be lower than those of the third-party, and since the third-party must pay income taxes on its profits, the annual revenue requirement on USMA's share of the required capital investment would be somewhat lower than that reported here.

The A options that make use of existing chillers tend to have lower costs than the plans requiring new chillers. In no case does the present value of the energy cost savings from the installation of new chillers exceed the capital costs of the new facilities.

LCCID Analysis

After conducting the screening analysis of the 68 plan/option combinations, the 12 most attractive (lowest cost) plans were selected and analyzed using LCCID. The results of the LCCID analysis are summarized in Table 16.* This table show, the present value (in October 1990) of total life-cycle costs including the principal component parts, the present values of investment costs, total energy costs, and maintenance and repair costs for each plan.

*The results are presented in detail for each plan in "Appendix E, Results of LCCID Analysis," of the unpublished report *Preliminary Report on Energy Supply Alternatives for the Year 2002 at USMA*, (Stanley Consultants, November 1990).

Table 16

Present Value of Life Cycle Costs

Plan	Present Value Initial Investment (in $1000s)	Present Value Energy Costs (in $1000s)	M&R Costs (in $1000s)	Total Life Cycle Costs (in $1000s)
1A	7,514	32,037	4,851	44,402
1E	11,728	34,403	4,881	51,012
2A	19,712	26,539	8,976	55,227
3A	11,025	33,707	4,829	49,561
3C	20,112	32,211	5,669	57,992
3D	13,685	32,612	4,806	51,103
5A	16,872	33,707	6,093	56,673
11A	15,810	29,351	6,191	51,352
11E	20,024	31,615	6,220	57,859
12A	15,980	30,839	6,078	52,896
13A	16,549	28,801	6,398	51,748
13E	20,763	31,114	6,428	58,305

Table 17 shows both SCI screening procedure equivalent annual costs and LCCID present value of life cycle costs for all plans economically evaluated, ranked by their equivalent annual cost. Of the original 68 plans, 44 were evaluated economically using the SCI screening procedure. The top 12 plans from the SCI screening procedure were then evaluated using LCCID. A ranking of the plans on the basis of the LCCID present value of life cycle costs would be preferred because the SCI screening procedure treats capital investment costs as if they were incurred as of the service date, rather than at earlier points in time. Because the SCI screening procedure explicitly ignores any allowance for interest during construction, it tends to understate the costs associated with capital cost-intensive plans.

Table 17 shows that the lowest cost plan analyzed is Plan 1A, the refurbishing of the existing gas/oil-fired plant with existing chillers. By both ranking measures, this plan has costs that are almost 12 percent lower than those of the second lowest cost plan, Plan 3A. Plan 3A includes a new central steam heat plant with gas/oil-firing and existing chillers. Plan 3A, in turn, is more than 2 percent lower in cost than Plan 1E, refurbishing of the existing gas/oil-fired plant with the existing centrifugal and reciprocating chillers replaced with absorption chillers.

Table 17

Comparison of Costs of Alternate Plans

Plan	SCI Screening Procedure Equivalent Annual Cost (in $1,000s)	LCCID Present Value of Life Cycle Costs (in $1,000s)
1A	13,463	44,402
3A	15,058	49,561
1E	15,400	51,012
11A	15,406	51,337
3D	15,510	51,103
13A	15,522	51,748
12A	15,877	52,896
2A	16,532	55,227
5A	17,157	56,673
11E	17,315	57,859
13E	17,445	58,305
3C	17,529	57,992
9A	17,595	
5D	17,609	
12E	18,090	
2E	18,327	
11B	18,663	
4A	18,748	
13B	18,813	
10A	19,060	
9E	19,236	
12B	19,373	
4D	19,419	
5C	19,629	
4AA*	19,811	
10AA*	20,129	
6A	20,362	

Table 17 (Cont'd)

Plan	SCI Screening Procedure Equivalent Annual Cost (in $1,000s)	LCCID Present Value of Life Cycle Costs (in $1,000s)
10E	20,431	
4DD*	20,649	
9B	20,661	
6D	21,033	
4C	21,438	
10EE*	21,496	
10B	21,946	
4CC*	22,668	
10BB*	23,012	
6C	23,052	
16D	24,554	
14A	34,863	
14E	37,936	
15A	39,584	
14B	41,456	
15E	42,887	
15B	46,296	

*Plan numbers with double letters indicate that the coal burning technology for that plan is fluidized bed combustion.

8 SCHEDULES

This section discusses approximate time frames required to implement the alternative plans evaluated in this study.

Before beginning design work for addition of steam, hot water, or electric generation facilities, a detailed engineering study should be conducted to define the operational parameters, environmental requirements, and sizes and types of equipment required for the plan selected. It will require 1 year to perform the various stages of review and comment by the USMA. Once the parameters are established, detailed design work can proceed. Approximately 1 year will be required to prepare the detailed plans and specifications.

Construction schedules will vary depending on the type of facility selected. The following time periods are estimated for the various types of plans for purchase, delivery, installation, and startup:

Plans	Construction Time
Refurbish Existing Plant	18 to 24 months
Gas Turbines or Diesel Engines	24 to 30 months
Gas/Oil-Fired Boilers or HTHW Generation	24 to 30 months
Coal-Fired Boilers or HTHW Generation	30 to 36 months
All Electric Plan	12 months

9 CONCLUSIONS AND RECOMMENDATIONS

Conclusions

Based on this study, the following conclusions can be drawn:

1. Peak steam demand is predicted to increase 6 percent from 185,000 lb/h (210,000 lb/hr including laundry boiler plant) in 1990 to slighty more than 196,000 lb/hr (over 221,000 lb/h including laundry boiler plant) by the year 2000.

2. Chilled water cooling capacity is predicted to increase 29 percent from 4135 tons (1705 tons absorption + 2430 tons motor driven) in 1990 to 5335 tons by the year 2000.

3. Electric load is predicted to increase 12.5 percent from 71,632,600 kWh (14,130 kW peak demand) in 1990 to 80,578,100 kWh (15,780 kW peak demand) by the year 2000.

4. These loads can be served by non-cogenerating facilities (all electric energy purchased from Orange and Rockland) or by cogenerating facilities (a portion of the electric energy required is generated and the remainder is purchased from Orange and Rockland).

5. Fuels considered for conventional technologies included gas, oil, coal, and coal/water mixture and are all technically feasible. This includes Plan Nos. 1 through 15 and Plan 16 (all electric).

6. Other technologies studied under Plan Nos. 17 through 27 are not recommended for the USMA at this time due to lack of technical or economic feasibility.

7. All environmental regulations for conventional fuel burning technologies can be met with conventional and emerging technologies, which are included with each plan studied. New regulations will likely eliminate the use of No. 5 fuel oil due to sulfur content; No. 2 fuel oil would be used in its place. Acquisition of the various permits required to implement any of the coal firing plans will likely be difficult due to expected local opposition.

8. Solid waste generated by coal or coal/water mixture firing should be disposed of at the coal mine.

9. Noise, transportation, and thermal impacts should be minimal for any plan located at any of the sites considered.

10. Requirements for adequate stack height to promote effluent dispersion (good engineering practice) may impact the visual aesthetics of the cadet area for Site Nos. 1 or 3. Site Nos. 2 or 4 should not impact the visual aesthetics of the cadet area.

11. Site No. 1 has the lowest cost of the four sites considered and will be in a designated industrial area.

12. Site No. 4 (remote from the Academy) will have a large economic impact on any plan considered ($23,000,000 added cost) and will impose plant operating efficiency penalties due to the higher steam and condensate pressures required. The only advantage of this site is the lack of visual impact on the Academy.

13. Replacement of the existing steam distribution system was considered versus reusing the existing system. The leaking portions of the condensate returns and underground conduits should be repaired or replaced now. A new system will add approximately $25,000,000 to the cost of any plan considered with little payback other than reduced maintenance costs for the first 10 years of operation.

14. Five chilled water options were considered: (1) use the existing chillers without change, (2) replace all chillers with a new central centrifugal chiller plant for non-cogeneration plans, (3) replace all chillers with a new central absorption chiller plant for cogeneration plans, (4) replace absorption chillers in buildings with centrifugal chillers for non-cogeneration plans, and (5) replace centrifugal and reciprocating chillers in buildings with absorption chillers for cogeneration plans. In all cases, the most economic option was to retain the existing chillers in operation without change.

15. Electrical distribution system improvements are provided with each plan as appropriate.

16. None of the coal-fired plans (either cogeneration or non-cogeneration) are very attractive economically due to their high capital costs and the high costs of coal and ash disposal in the area of the USMA. This is typical for small plants of this type. The use of a coal/water mixture in the existing power plant building (Plan 2A) is the lowest cost coal-fired plan, but the equipment required will create a very crowded boiler room and fuel availability is limited at this time.

17. The lowest cost plan analyzed was Plan 1A, refurbishing the existing power plant with new higher pressure gas/oil-fired package boilers and new steam turbine generators and using the existing chillers without change. The present value of life cycle costs for this plan is $44,402,000, while the estimated present day capital cost is $19,959,000. The coal/water-fired version of this plan is 2A and the present value of life cycle costs is $55,227,000, while the estimated present day capital cost is $51,128,800.

18. The lowest cost non-cogeneration plan is Plan 3A, gas/oil-fired package steam boilers in a new plant. The present value of life cycle costs for this plan is $49,561,000 and the estimated present day capital cost is $29,286,000. The lowest cost hot water boiler plan is 5A, which includes gas/oil-fired hot water generators, with present value of life cycle costs of $56,673,000 and estimated present day capital cost of $44,818,000.

19. The lowest cost cogeneration plans in a new plant are Plans 11A, 13A, and 12A. These plans consist of two simple cycle gas turbine generators with heat recovery boilers for Plan 11A, two diesel engine generators with heat recovery boilers for Plan 13A, and one combined cycle gas turbine for Plan 12A. The present value of life cycle costs for each of these plans are $51,337,000, $51,748,000, and $52,896,000, respectively, while the estimated present day capital costs are $41,995,000, $43,958,000, and $42,447,000, respectively.

20. The highest cost plans were Plan 16D, all electric, and the Third-Party financed cogeneration, Plans 14 and 15, which should not be considered due to their high life cycle costs.

Recommendations

Based on this study, the following recommendations are made:

1. Plan 1A, refurbish the existing power plant with new high pressure gas/oil boilers and new steam turbine generators, is the lowest cost plan and is recommended as the best plan at this time.

2. If the USMA decides a new plant must be built on a new site as recommended by the Hillier Group in the Master Plan Report, then non-cogeneration Plan 3A, new gas/oil-fired boilers or cogeneration Plan 11A - two simple cycle gas turbine generators with heat recovery boilers should be used.

3. Site 1 is recommended as the best site for new generating plants.

4. Use of the existing steam distribution system should be continued with repairs and replacements as needed rather than constructing a new distribution system.

5. A new central chiller plant is not recommended due to its high capital cost and poor payback. USMA should continue to use the existing water chillers or, if energy conservation at higher cost is acceptable, replace absorption chillers with centrifugal chillers for non-cogeneration plans and replace motor driven chillers with absorption chillers for cogeneration plans.

6. Fuel costs are fluctuating rapidly and should be carefully monitored since a large price change costs could affect the ranking of some plans relative to other plans.

7. USMA should assess fuel costs, electrical energy costs, and capital costs for the top five economically ranked plans (1A, 3A, 1E, 3D, and 11A) before proceeding with a construction project scheduled for the years 2000 to 2002.

The above recommendations are based on technical considerations and life-cycle cost estimates and do not reflect availability of capital funds.

METRIC CONVERSION TABLE

1 ft	=	0.305 m
1 lb	=	0.453 kg
1 gal	=	3.78 l
1 psi	=	703 kg/m^2
1 ton cooling	=	3.517 kW
1 Btu	=	1,054.8 J
0.55(°F-32)	=	°C

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